Power Market Design with a High Wind Power Share

Simulations and Analysis

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Further Developing Europe's Power Market for Large Scale Integration of Wind Power

D7.5 – Power Market Design with a High Wind Power Share: Simulations and Analysis

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1 INTRODUCTION

1.1 Objectives of Market Modelling

In this document the functioning of the European electricity markets with a high share of wind energy is analyzed. The objective is to allow for market efficiency evaluation for different market designs and stages of integration. The analysis is based on the outcomes of market simulation with different levels of market integration and for different lead times for trade (i.e., different types of generation plant being available for rescheduling and different reserve requirements for wind power balancing). The results are quantified by means of selected indicators.

In particular we may expect that:

- with high wind power penetration, some market designs will be more beneficial than others in terms of socio-economic cost, price volatility and required ancillary services for system operation;
- the effect of different market rules can be determined by sensitivity analysis; some measures, e.g., efficient cross-border allocation or short gate closure times, may have a much stronger effect on wind power trade than others;
- the value of European market integration in different stages can be quantified for different cases.

1.2 Starting Point

The market analysis within TradeWind is based on the understanding that trans-continental trade of electricity from wind energy in Europe still faces barriers. The barriers that prevent wind power from accessing the internal electricity market are relatively clear. Long gate closure times for day-ahead markets that do not allow for generation to efficiently participate in cross-border trade, and the fact that security rules in the interconnected grid are still applied on the national bases. This implies that large scale short term cross-border trade is not yet possible (this holds for both wind generation, and for conventional generation as well). The above reasons are complemented with technical constraints, such as cross-border interconnection capacity limits.

In the past two years, the European integration of power markets has evolved very fast, especially in western and northern Europe. Recent developments are:

- the launch of the tri-lateral market coupling between the Netherlands, Belgium and France in 2006,
- the memorandum of understanding towards a penta-lateral market coupling between the Netherlands, Belgium, France, Luxemburg and Germany scheduled for 2009,
- the establishment of bidding areas in Germany for day-ahead and intra-day trade on the Nord Pool Spot market in 2006,
- the establishment of the all-island market in Republic of Ireland and Northern Ireland in 2007,
- the establishment of intra-day market in most European countries,
- ongoing discussions on cross-border exchange of system services such as reserve capacity,
- the third liberalisation package, calling for the establishment of European entities for energy regulation (Agency for the Cooperation of Energy Regulators ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E).

The process of European integration of power markets has largely been fostered by the Regional Initiative for regional energy markets of the European Regulators' Group for Electricity and Gas (ERGEG) [ERG06]. The ERGEG proposes to pursue the development of seven regional electricity markets, each comprising several national markets as of today.

Regional markets should fulfil a number of criteria including a functioning spot market. Such markets would allow for an efficient exchange of wind power, based on properly regulated trading mechanisms. Moreover, regional initiatives are also an opportunity for the involved TSOs to work more closely together, giving the chance for increasing the efficiency of data exchange, harmonization of operational procedures, etc.

1.3 Approach

The followed approach is based on the understanding that the main criteria influencing or limiting wind power trade over national frontiers are

- the efficiency of the cross-border exchange (spatial dimension),
- the flexibility in time, depending on market gate closures and the power plant park (time dimension) and
- the available interconnector capacity (technical constraints).

In addition, market outcomes will depend on the installed wind power capacity and the wind energy generation over time. Finally, they are influenced by macro-economic parameters like fuel prices and CO_2 prices, by the existing conventional power plants, and the electricity demand over time.

For the simulation of future market outcomes two simulation tools are applied, namely, Prosym® and the Wilmar Planning Tool. Simulations with both tools are carried out for a few fundamental scenarios defined by the installed wind power capacity, the electricity demand and the energy economic scenario for a given target year. Parameters to be varied are available or net transfer capacity (ATC or NTC, respectively), market gate closure time or deadline for rescheduling of dispatch decisions and the extension of the overall market area.

The result of these simulations are socio-economic and business indicators reflecting the suitability of different market designs for the assumed wind energy generation within the given energy economic context.

1.4 Guide to the Reader

In Section 2, the report proceeds with a description of the modelling tools applied. The macro-economic and energy-economic boundary conditions for a model of the future European electricity market are described in Section 3. Section 4 describes the scenarios for the specific model runs as they have been carried out with each of the two simulation tools. The indicators for presenting and analysing the market results are defined in Section 5.

The results from all runs with the different tools are presented Section 6, including also a discussion of of the interpretation. Section 7 contains a summary and conclusions.

2 MODELING TOOLS

2.1 Prosym® Simulation Model

The production simulation tool Prosym is a probabilistic, hourly chronological power market simulation model (a stochastic linear optimization model). The required input data consist of a basic set of annual hourly loads, data representing the physical and operating characteristics of the generation plants and data of transmission areas and their links.

KEMA has developed a full European market model in the framework of the "Analysis of the network capacities and possible congestion of the electricity transmission networks within the accession countries" study, finished in 2005, for the European Commission - Directorate-General Energy and Transport (TREN). The model has been also used in several other projects. The EU model structure was used for the market simulations within TradeWind WP7.

The Prosym probabilistic mode offers additional sub-method refinements as: distributed maintenance, detailed unit commitment and dispatch control, rules that regulate how generators may interact, emissions as proportion of fuel burn or of energy output (Third-order equation, Exponential equation, X – Y points).

The hour-by-hour model allows the simulation of chronological events as plant availability and technical features, load changes, reserve changes on transmission area level (due to changes in wind forecast), available transmission capacities, and others. These events together with the transmission and plant constraints such as start-up times, thermal plant ramp rates, thermal plant up and down times, hourly spinning and non-spinning reserve, determine zonal market clearing prices and volumes for each hour in each country, chronological, using implicit allocation mechanisms. A linear programming model is used to solve the pre-commitment (week ahead), problem with transmission constraints and ancillary service requirements.

For the Ancillary services modelling we have used the spinning[1] and the non-spinning reserve[2]. The spinning reserve is used for the N-1 rule of UCTE. For Trade Wind we have used the non-spinning reserve to model the wind forecast error. The non-spinning reserve is calculated based on the wind power production and the wind forecast error, such being influenced by the wind forecast quality.

Prosym allows User defined penalties for not meeting load and not meeting reserves. These are set at equal values by KEMA.

Within Prosym, the power system configuration is a representation of a scheme of available power units and transmission capacity. A Transmission Area is a zone containing load and generation that does not have significant intra-zonal transmission constraints and have exchange energy with neighbour Transmission Areas (for comparison, in Wilmar a Transmission area is called Region).

Prosym offers different modes of operation to take account of random effects, such as forced outages. For our simulations, we have used the preferred calculating method of the model, the convergent Monte Carlo method. This method causes carefully distributed outages throughout each period. A unit with an outage rate of x % is then available exactly 1-x of the time. This allows fast simulations of long periods of time, as considerably less iterations are necessary. This method is tuned to help accounting for the effect of outages at different times of day and seasons of the year.

In addition, specific modules allow simulating a multi-area model with given transmission constraints. Most of these characteristics may change every hour of the year.

Prosym consists of a suite of different modules (additional software packages), which can be combined with the core Prosym tool. For our study we have added the modules LOADFARM and MULTISYM.

MULTISYM is a superset of PROSYM that is able to convert PROSYM into a multi-area model by taking transmission constraints into account. MULTISYM can handle mode independent and

[1] UCTE: Primary and secondary reserve

[2] UCTE: Tertiary reserve

connected transmission areas with different topologies. We have limited the power exchanges between countries by the NTC values.

2.2 Wilmar Planning Tool

Wilmar Planning Tool

The Wilmar Planning Tool is used to analyse the consequences of different market rules for the operation of a future European power system. The Wilmar Planning tool consists of a number of sub-models and databases as shown in Figure 1. The main functionality of the Wilmar Planning tool is embedded in the Scenario Tree Tool (STT) and the Scheduling model (SM).

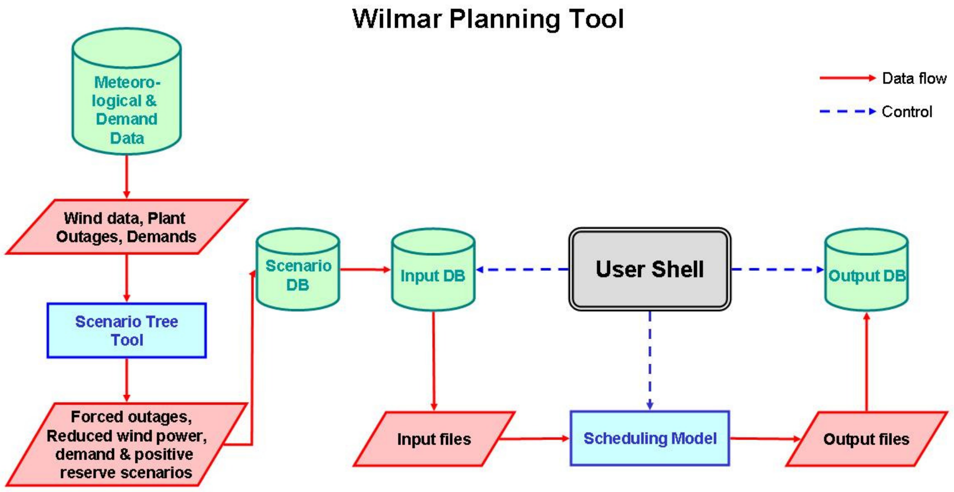

Figure 1. Overview of Wilmar Planning tool. The green cylinders are databases, the red parallelograms indicate exchange of information between sub models or databases, the blue squares are models. The user shell controlling the execution of the Wilmar Planning tool is shown in black.

The Scenario Tree Tool

The Scenario Tree Tool generates stochastic scenario trees containing three input parameters to the Scheduling Model: the demand for positive reserves with activation times longer than 5 minutes and for forecast horizons from 5 minutes to 36 hours ahead (in the following named replacement reserve), wind power production forecasts and load forecasts. The main input data for the Scenario Tree Tool is wind speed and/or wind power production data, historical electricity demand data, assumptions about wind production forecast accuracies and load forecast accuracies for different forecast horizons, and data of outages and the mean time to repair of power plants. The demand for replacement reserves corresponds to the total forecast error of the power system considered which is defined according to the hourly distribution of wind power and load forecast errors and according to forced outages of conventional power plants. Thereby it is assumed that the n^{th} percentile of the total forecast error has to be covered by replacement reserves. The calculation of the replacement reserve demand by the Scenario Tree Tool enables the Wilmar Planning tool to quantify the effect that partly predictable wind power production has on the replacement reserve requirements for different planning horizons (forecast horizons). For each time step new forecasts (i.e. a new scenario tree) that consider the change in forecast horizons are applied. This decision structure is illustrated in *Figure 2* showing the scenario tree for two planning periods. For each planning period a two-stage, stochastic optimisation problem is solved.

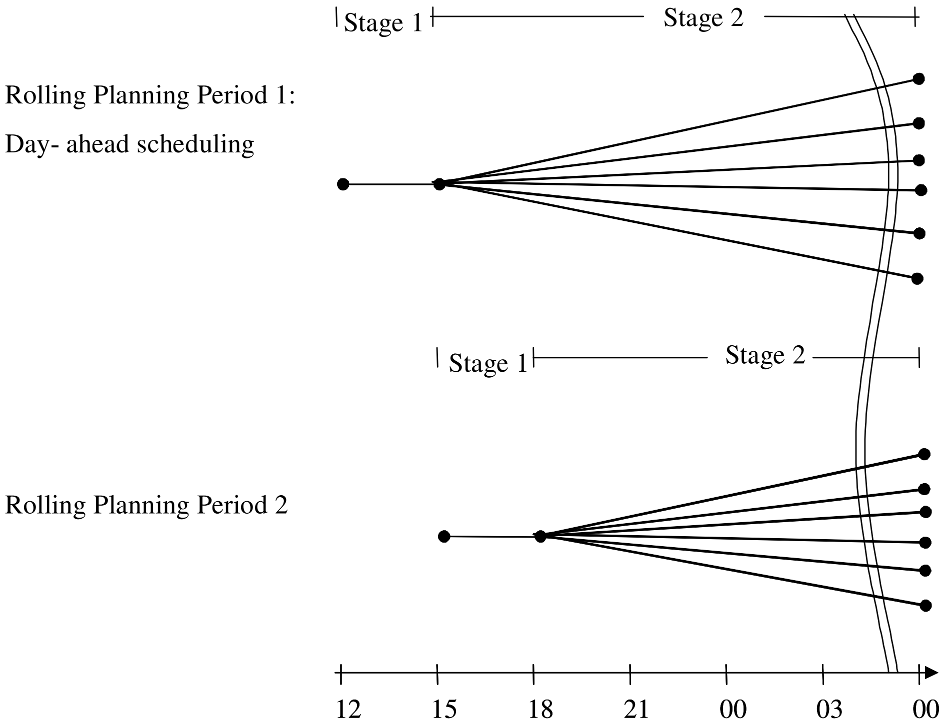

Figure 2. Illustration of the rolling planning and the decision structure in each planning period.

The Scheduling model

The Scheduling model is a mixed integer, stochastic, optimisation model with the demand for replacement reserves, wind power production forecasts and load forecasts as the stochastic input parameters, and hourly time-resolution. The model minimises the expected value of the system operation costs consisting of fuel costs, start-up costs, costs of consuming CO2 emission permits and variable operation and maintenance costs. The expectation of the system operation costs is taken over all given scenarios of the stochastic input parameters. Thereby it has to optimise the operation of the whole power system without the knowledge which one of the scenarios will be closest to the realisation of the stochastic input parameter, for example the actual wind power generation. Hence, some of the decisions, notably start-ups of power plants, have to be made before the wind power production and load (and the associated demand for replacement reserve) is known with certainty. The methodology ensures that these unit commitment and dispatch decisions are robust towards different wind power prediction errors and load prediction errors as represented by the scenario tree for wind power production and load forecasts. Information about the Wilmar Planning Tool can be found in [Bar06; Mei08; Wil06].

3 ENERGY ECONOMIC BOUNDARY CONDITIONS

3.1 Common Values

The overall energy economic boundary conditions have been chosen the same for all simulation work in TradeWind. This concerns marginal costs of power generation, annual profiles of electricity demand, assumptions on the installed capacity of conventional power plants and scenarios for the net transfer capacities between countries. Distributed generation from biomass and hydropower have also been taken into account; photovoltaics (PV) were neglected in the model. Notably, in September 2008, the European PV Industry Association (EPIA) has increased their target for 2020 from a few percent to 12% of EU electricity demand to be generated from PV. If this ambitious target is approached, PV need to be taken into consideration in future national and international transmission and market studies.

In addition, due to the slight differences in approach to market modelling, the two simulation tools applied in WP7 partly require different data or data with different degree of detail. Also, the geographical areas covered by both simulation tools are different. While the common boundary conditions are specified here, the input data and boundary conditions that are specific to one of the tools are given in the sections 3.1.2 and 3.1.3.

Electricity Demand

As for the power system modelling in WP5 and WP6 the electricity demand is based on empirical hourly load data for 2006 and an extrapolation of the load for the third Wednesday for January and July up to 2030. The forecast for any of the specified years can be calculated using the relative increase/decrease and the hour by hour load profile for year 2006.

For the UCTE member countries, the load data originate from the System Adequacy Forecast of the UCTE [Uct07]. Data for Great Britain and Ireland are from National Grid [Nat07] and Eirgrid [Eir07], respectively. Load profiles for Nordel have been provided by Nord Pool [Nor07a] with an extrapolation from [Nor07b]. Furthermore, extrapolations to 2030 are partly also based on scenarios from Eurelectric [Uni07]. Notably, the Eurelectric demand scenario is particularly conservative for 2030, assuming a significantly stronger increase in electricity demand than, e.g., the European Commission's 2007 baseline scenario [Cap08]. The overall annual demand used in TradeWind is shown in . The data per country are listed in Appendix 1.

The load forecast for the years 2007, 2008, 2010, 2015, 2020 and 2030 was provided by WP3. It is available in Excel or as Matlab file. The format is specified in Annex C of the WP3 technical report [Kor07].

Table 1: Annual electricity consumption for power flow and market modelling in TWh; scenario based on Eurprog 2006 [Uni06]

Year	2005	2008	2010	2015	2020	2030
Total [TWh]	3288	3482	3636	3880	4126	4586

In the market model, demand is considered unelastic. This means it is considered fixed for each hour and independent from the clearing price. No demand side management was assumed in the models.

Conventional Power Plants

The shares of different conventional power plants in the different countries have been derived from the UCTE System Adequacy Forecast (SAF) – *Scenario B* (*Best Estimate*). In contrast to the *Conservative Scenario A*, the Best Estimate Scenario "takes into account future power plants whose commissioning can be considered as reasonably probable according to the information available for the TSOs: commissioning resulting from governmental plans or objectives, concerning for example the development of renewable sources in accordance with the European legislation, or estimation of the future commissioning resulting from the requests for connection to the grid of from the information given by producers to the TSOs” [Uct07].

Within TradeWind, tables of different generation plant per fuel type for all countries have been developed in WP3 [Kor07]. These are largely based on the UCTE SAF and complemented with data from Eurelectric [Uni07]. While the power flow calculations in WP5 and WP6 and the calculations with the Wilmar model are based on the SAF of 2007 [Uct07], for the Prosym calculations the SAF issued in December 2007 [Uct08] has been used. The absolute values and shares of different types of generation plants differ only marginally between the two versions of the SAF. Finally, the generation data for use in Prosym have been complemented by generation data from other sources available at Kema Consulting (i.e., the power plant data base offered by Platts).

Marginal Costs of Power Generation

The marginal costs of power generation as applied for dispatch decisions in the market modelling tools are calculated as

$$MC = (CC+FC) / \eta + O\&MC \qquad (1)$$

with

- MC the marginal cost in €/MWh of electricity,
- CC the costs of consuming CO2 emission certificates in Euro/MWh of primary energy equivalents,
- FC the fuel cost in €/MWh of primary energy equivalents,
- H the average conversion efficiency for a given fuel type and
- O&MC the costs for operation and maintenance in €/MWh of electricity.

The marginal cost scenarios are based as much as possible on the recent EC Energy Baseline scenario (European Energy and Transport Trends to 2030 [Cap08]). Where this was not possible, other transparent reference publications where found [IEA08],[Nor06].

Table 2 and Table 3 show the fuel prices and conversion efficiencies as applied for market modelling in TradeWind. The contribution of variable operation and maintenance costs to the marginal costs is listed in Table 4. Additional costs associated to the price of tradable CO_2 emission allowances are applied as listed in Table 5. The figures listed in Table 2 to Table 5 have been applied to market modelling in WP7 and have also functioned as input to the power flow modelling in WP5 and WP6 [War08], In the Prosym simulation tool only Table 2 and Table 5 have been applied, because the simulation tool has more accurate efficiency rates, based on polynomial heat rate curves which are specific for type of plant[3] and the commissioning year. Moreover, Prosym used plant-related operation and maintenance costs, different per type of plant.

Table 2. Fuel prices per fuel type for power generation (from [Cap08], with 1.25 US$/€ and 8 NOK/€))

Fuel Prices in Real €05 / MWh (primary energy)							
€05 / MWh	**2005**	**2008**	**2010**	**2015**	**2020**	**2025**	**2030**
Oil	25.7	25.7	25.7	27.3	28.8	29.3	29.6
Gas	16.3	18.2	19.5	20.4	21.7	22.2	22.4
Coal	7.0	6.7	6.5	6.7	6.9	7.0	7.0
Biomass [IEA08]	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Nuclear [Nor06]	5	5	5	5	5	5	5

[3] For example for gas the types: CCGT (combined cycle gas turbine), GT (gas turbine), BFG (blast-furnace fuel gas), and others

Table 3. Average conversion efficiency for conversion of fuel into electricity (from [Cap08])

Net electricity efficiency rates							
	2005	**2008**	**2010**	**2015**	**2020**	**2025**	**2030**
Oil	29%	34%	37%	38%	38%	40%	42%
Gas	39%	43%	46%	48%	49%	50%	50%
Coal	31%	33%	34%	36%	37%	39%	41%
Biomass	23%	27%	29%	31%	33%	34%	34%
Nuclear	100%	100%	100%	100%	100%	100%	100%

Table 4. Variable operation and maintenance costs for different fuel types

O&M Costs in Real €05 / MWh (electricity)	
€05 / MWh	**all years**
Oil[4]	5.0
Gas: CCGT [IEA08]	1.7
Coal [IEA08]	2.0
Biomass [IEA08]	3.0
Nuclear [Nor06]	6.3
Hydro [Nor06]	2.5

Table 5. Prices for tradable CO_2 emission allowances (from [Cap08])

CO_2 Prices in Real €05 / tonne							
€05/tonne	**2005**	**2008**	**2010**	**2015**	**2020**	**2025**	**2030**
CO2	5	20	20	21	22	23	24

Wind Power Generation

The scenarios for installed wind power capacity for market modelling in WP7 have been taken from WP2 [Too07]. There, a medium scenario was developed as best guess accompanied by low and high scenarios for sensitivity analysis. WP7 mainly relies on the medium scenarios for 2020 and 2030. In addition calculations have been carried out with the medium scenario for 2008 in order to view the market results without any significant increase of wind power as from today.

Table 6. Installed capacity for the target years in Europe (medium scenario, from [Too07])

Year	**2005**	**2008**	**2010**	**2015**	**2020**	**2030**
Installed capacity [MW]	42 331	66 503	90 019	143 680	205 835	279 580

In WP7, time series of wind power generation have been applied on a per-country base with a split for Denmark West and East in the Prosym model runs. The data are based on wind speed time series for the Reanalysis data points as calculated in WP2 [McL07] with the necessary correction factors for terrain and offshore sites applied as specified in [McL08a, McL08b].

The available wind speed time series from Reanalysis had a time resolution of one sample per six hours. While this is acceptable for power flow calculations, for the analysis of power markets at least an hourly resolution was required in order to properly reflect rescheduling decisions as a function of uncertainties in wind power generation and demand. Therefore, hourly variation was modulated onto the wind speed time series with 6-hourly resolution. The hourly variation was generated by a spectral approach ensuring the overall power spectrum of the resulting wind power time series for periods down to one hour is equal to the spectrum of measured wind power generation. The approach has

[4] Educated guess, Sintef and 3E, April 2008.

been validated on a per-country base for Denmark, Germany and Spain. The method and verification is specified in [Soe08].

Finally, the wind speed time series with hourly variation have been converted into power by applying the equivalent wind power curves developed in WP2 [McL08a]. The wind power time series have then been aggregated for each country as input for the Prosym model. The scenario tree tool in Wilmar has used the hourly wind speed time series as input together with the scenarios for installed wind power generation, and assumptions about load and wind power forecast uncertainties dependant on forecast horizon to generate scenario trees (see Section 3.3).

The market simulations with Prosym are based on the wind speed data for the year 2004 in the Reanalysis data set from WP2, while the Wilmar simulations are based on 2006.

Transfer Capacity between Countries

The possibilities for international power trade are constrained by the cross-border transfer capacities between countries. Note that the terms net transfer capacity (NTC) and available transfer capacity (ATC) are used as synonyms in the current context of market modelling. The difference is especially important in real congestion management where transfer capacity is allocated in several phases over time. The European Transmission System Operators (ETSO) define NTC as “the maximum exchange programme between two areas compatible with security standards in both areas” and ATC as “the part of the NTC that remains available after each phase of the allocation procedure for future commercial activity” [ETS01].

For the market model calculations two NTC scenarios have been applied. The scenarios originate from WP6. In WP7 they are referred to as:

- 2020 Base case NTC data

The 2020 Base Case describes the NTC data as they may most probably be expected for the year 2020. It departs from the NTC data between countries as of today [ETS07]. In addition it takes into account the grid reinforcements that are currently in the realisation or planning phase and where no significant delay of the realisation is expected. The upgrades are in line with the Priority Interconnection Plan [Com06].

- 2030 Best Case NTC data

The 2030 Best Case describes a case of high NTC values. The data set may be applied to 2020 as a best case scenario or as a reasonable estimate for 2030. This scenario is a result from WP6. It contains the grid reinforcements required for mitigating congestion at critical transmission corridors as identified in WP6 [Kor08]. Most reinforcements as compared to the 2020 Base Case are additional high-voltage DC connections.

In order to estimate the contribution of new cross-border lines to the NTC between two countries, a simplified proportional approach has been applied:

- For new cross-border lines the NTC value is increased by the share of the additional cross boarder line capacity according equal to the ratio of the initial NTC to the total line capacity.
- For HVDC lines the contribution to the NTC is set equal to the capacity of the new HVDC line.

The NTC data for both cases are listed in Appendix 2.

3.2 Specific Data for Prosym Simulations

The dataset used for the Trade Wind simulations with Prosym includes the countries listed in Table 7. The following countries (or regions) have not been covered in the Prosym model for TradeWind: Sweden, Finland, Ireland, North Ireland, East and South-East Europe countries.

Table 7: Countries and country codes as covered in the Prosym model calculations

1	Austria	AU
2	Belgium	BE
3	Swiss	CH
4	Czech Republic	CZ
5	Denmark East	DK-E
6	Denmark East	DK-W
7	Germany	DE
8	Spain	ES
9	France	FR
10	Great Britain	GB
11	Hungary	HU
12	Italy	IT
13	Luxemburg	LU
14	the Netherlands	NL
15	Norway	NO
16	Poland	PL
17	Portugal	PT
18	Slovenia	SI
19	Slovakia	SK

The generation data set covers selected countries with about 4000 power plant units. In theory, it would be better to model these plants individually, with the corresponding technical data, age and efficiency. To facilitate the simulations we have modelled generation units on an aggregated level per country, thus reducing the number of power plants units to 3174 as part of 529 power plants (one power plant have maximum 10 units with the same installed capacity but different commissioning years). This approach has the advantage to reduce the computation time, thus making it possible to study a larger number of different scenarios. The dataset applied to Prosym is based on information from various sources, namely: the Platts WEPP database (main input for power plants commissioned before 2008), the UCTE System Adequacy Forecast report (2008–2020) scenario B from December 2007, the Eurelectric EURPROG 2006 report (2000–2030), the internal KEMA database and discussion with KEMA's power generation experts.

The following types of power plant have been considered:

- Hydro power plants (HPP): pomp storage, reservoir and Run Of River
- Thermal plants:
    - Boiler-steam turbine plants (STs): nuclear, lignite, hard coal, gas, oil, biomass
    - Gas turbines (GTs)
    - Combined cycle gas turbines (CCGTs)
- Wind turbines

The hydro power plants (HPP) are differentiated into run-of-river, reservoir and pumped storage plants. The possible output of hydropower plants depends mainly on the total hydro inflow and its distribution during the year, and may thus be subject to considerable variations both during a single year as well as across several years:

Storage hydro is characterized by a monthly energy amount in GWh and maximum generation capacity in MW. The variation over the year of hydro inflows is specified by a monthly energy pattern that is profiled, based on several years from UCTE data and KEMA assumptions. The storage hydro amount and generation capacity were estimated from various sources such as EURPROG2006 generation data, and country specific energy agencies or generation companies.

The production of run-of-river is entirely dependent on the actual water inflow and is thus of a largely stochastic nature. We have therefore modeled run-of-river plants with maximum monthly generation capacities that may vary according to a monthly pattern that is profiled based on several years from UCTE data and KEMA assumptions. (Run-of-river plants are modeled as base load plants with a monthly maximum capacity.) Information about generation capacity for run-of-river plants is obtained in a similar way as for reservoir hydro. Pump storage is treated as reservoir hydro, in order to avoid a significant increase of computational time.

The modelling of the thermal power plants is made for groups of power plants formed through aggregation. Thus, the power plants are grouped by technology, fuel, age and generation capacity in order to reduce the number of power plants and the computation time. The modeling of a group of thermal power plant is made using technical parameters as: number of units, minimum and maximum capacity, heat rate curve[5] (second category polynomial function), ramp rate (up and down), run up time, minimum down time, reserve contribution, forced outages rate, maintenance outage rate, variable operation and maintenance (O&M) costs, fixed start up costs, fuel start up quantities, and others. For the unplanned maintenance outages we considered the convergent Monte Carlo method. For other technical parameters average values have been considered.

The modelling of CHP plants was made similar to the rest of the thermal power plants i.e. with no must run commitment for heat delivery.

Wind power is modelled as a power station with an hourly max capacity up to the realized wind energy, provided by WP2 TradeWind. The stochastic uncertainties of wind power generation are taken into account by means of synthetic time series of the required non-spinning reserve on market area level and are calculated based on a methodology developed by KEMA in collaboration with Technical University Delft. Both hourly profiles wind power realization and non-spinning reserves are input data for Prosym power market simulation.

The methodology for the calculation of non-spinning reserve capacity was used by KEMA in a couple of projects to evaluate the interaction of the expected 6 GW offshore wind power in the Netherlands with the power system and power market. Non-spinning reserve is a function of wind speed, system features and the wind forecast quality i.e. the number of hours ahead wind forecast is made.

For the wind modelling we have considered the wind forecast 24 hours ahead (Day–1) and 3 hours ahead (T-3). The non-spinning reserve for Day-1 is calculated on hourly base as difference between wind power production with a forecast error of 1,6 m/s[6] and wind power production with a forecast error of 0 m/s (the realised wind production). The error of 1,6 m/s has been chosen by KEMA based on previous studies. The non-spinning reserve for T-3 is calculated on hourly base as proportion of the non-spinning reserve on Day-1, in line with TradeWInd WP2 [7].

In conclusion, the non-spinning reserve requirements (called 'demand for non-spinning reserve' in Wilmar description) vary hourly based on wind forecast quality and wind production, while the spinning reserve requirements are a yearly capacity value (see Table 7).

For Prosym modelling and simulation the reserve deficiency costs has been defined equal to the energy-not-served (called value of lost-load in Wilmar) and fixed to 275 €/MWh[8].

3.3 Specific Data for Wilmar Simulations

Twenty-five countries are included in the model runs with each country represented by one region (see Table 8). Thereby only capacity limits in the transmission lines between countries are included, and the transmission grid within countries does not influence results. The reason for the aggregated

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[5] for each technology, fuel and commissioning year of the plant, a different heat rate curve is used based on a quadratic polynomial function; Prosym allowed multiple heat rate representations (up to fifth-order polynomial function),

[6] average standard deviation

[7] Wind power RMSE (Day-1) = 11%; Wind power RMSE (T-3) = 5%, in line with [Gie07].

[8] The electricity price of an open cycle gas power plant

representation of the European power grid is that we wanted to include as many countries in the model as possible to study the operation of the whole European power system. As calculation times are long and memory usage high when doing stochastic optimisation, it was not possible to include a more detailed representation of the power grid for such a large geographical case. DC load flow calculations although possible with the model was not used due to the aggregated grid, i.e. a transmission line in the version of the model used in this study is represented by an average loss proportional to the power exchanged and an upper limit on the power exchange each hour. Wilmar does not include forced outages of power plants.

For the creation of scenario trees with wind power production forecasts, load forecasts and forecasts of replacement reserves, the wind power time series available from [Soe08] are combined with assumptions about load forecast and wind power production forecast errors for forecast horizons 1-36 hours ahead, and with scenarios of installed wind power capacity in each country in 2020 and 2030 [Too07]. The resulting average demand for replacement reserves depending on forecast horizon is given in Table 21 and Table 22 (see Appendix 4).

The assumed demand for spinning reserve is taken from existing grid code values or determined as the largest power plant installed to reflect a n-1 criteria. The same spinning reserve demand is assumed in 2020 and 2030 and given in Table 9. Prosym has used the same spinning reserve demand values for 2020 as presented in Table 7.

Table 8 Countries included in Wilmar model runs and the name of the corresponding region representing the country.

Country	Region	Country	Region
Austria	R_AT	Italy	R_IT
Belgium	R_B	Luxembourg	R_L
Bulgaria	R_BU	Netherlands	R_N
Croatia	R_HR	Norway	R_NO
Czech Republic	R_CZ	Poland	R_PL
Denmark	R_DK	Portugal	R_P
Finland	R_SF	Romania	R_RO
France	R_FR	Slovakia	R_SK
Germany	R_DE	Slovenia	R_SV
Great Britain	R_GB	Spain	R_ES
Greece	R_GR	Sweden	R_SE
Hungary	R_HU	Switzerland	R_CH
Ireland	R_IR		

Table 9 Demand for positive and negative spinning reserve in each country in 2020 and 2030.

Region	Positive spinning reserve demand [MW]	Negative spinning reserve demand [MW]	Region	Positive spinning reserve demand [MW]	Negative spinning reserve demand [MW]
R_AT	465	245	R_IR	616	616
R_B	227	227	R_IT	1663	1663
R_BU	225	225	R_L	31	31
R_CH	318	318	R_N	408	408
R_CZ	495	495	R_NO	503	201
R_DE	4000	3000	R_P	252	252
R_DK	185	60	R_PL	725	725
R_ES	1372	1372	R_RO	354	354
R_FR	1310	1310	R_SE	569	241
R_GB	1800	1800	R_SF	464	141
R_GR	349	349	R_SK	130	130
R_HR	80	80	R_SV	68	68
R_HU	204	204			

Photovoltaics, wave power, tidal power can be included in the model in the same way as wind power or just treated as an hourly production time series. For TradeWind, however, these types of production were not included in the model runs. The heat side of combined heat and power plants were ignored i.e. thermal plants were treated as condensing power plants.

For the Wilmar simulations, the following unit groups of power plants were created based on the data from the UCTE SAF [Uct07]:

- Nuclear power
- Coal power
- Lignite power
- Natural gas power (combined cycle gas turbines)
- Fuel oil power (open cycle gas turbines)
- Light oil power (open cycle gas turbines)
- Biomass power representing all types of biomass used for power production (e.g. wood, straw).
- Hydro power with reservoir
- Pumped hydro storage

For hydropower the production capacity of hydropower and pumped hydro storage, reservoir capacity and yearly inflow data was available (see Table 7 in [Kor07]). To distribute the reservoir capacity on hydropower and pumped hydro storage, it was assumed in WP7 that pumped hydro storage on average has a reservoir able to store 8 hours of maximum pumping. Pumping capacity was set equal to generation capacity of the pumped hydro storage, and round-trip storage efficiency of 0.75. Run-of-river hydropower was included in hydropower with reservoir thereby overestimating the flexibility of hydropower. Countries with low reservoir capacities will still have to run the hydropower production following the variation in hydro inflow rather close in order to respect the maximum and minimum levels of the storage.

All in all 180 unit groups represent the power production portfolio in the 25 countries in 2020, and 177 unit groups in 2030. TradeWind deliverable D3.2 [Kor07] did not provide all data for unit restrictions required by the Wilmar Planning tool. Based on plant data available at Risø DTU the assumptions detailed in Table 10 concerning plant capabilities were made. Due to the very aggregated representation of units in the model runs, a linear representation of the unit commitment decision of unit groups is sensible, i.e. any fraction of the installed capacity of a unit group can be brought online, in contrast to a binary representation where either zero or all capacity can be brought online.

Table 10 Power plant characteristics assumed in Wilmar model runs for 2020 and 2030; same characteristics for power plants of the same type situated in different countries

Technology	Fuel	Maximum efficiency	Part-load efficiency	Min stable operation limit/Maximum power	Min. operation time [h]	Min. shut-down time [h]	Spinning reserve capability [MW spinning reserve/MW capacity]	Start-up fuel consumption [GJ/MW started]	Start-up time [h]
Biomass_2020	Biomass	0.33	0.3	0.5	4	3	0.06	16	4
Biomass_2030	Biomass	0.34	0.31	0.5	4	3	0.06	16	4
Coal_2020	COAL	0.37	0.34	0.5	8	8	0.125	13	4
Coal_2030	COAL	0.41	0.38	0.5	8	8	0.125	13	4
FuelOil_2020	FUELOIL	0.38	0.35	0.2	4	4	0.2	3	1
FuelOil_2030	FUELOIL	0.42	0.39	0.2	4	4	0.2	3	1
Gas_2020	NAT_GAS	0.49	0.44	0.5	1	1	0.08	16	2
Gas_2030	NAT_GAS	0.5	0.45	0.5	1	1	0.08	16	2
Hydro_2020	WATER	1	1	0	0	0	0.125	0	0
Hydro_2030	WATER	1	1	0	0	0	0.125	0	0
LightOil_2020	LIGHTOIL	0.38	0.35	0.1	1	1	0.2	1	0
LightOil_2030	LIGHTOIL	0.42	0.39	0.1	1	1	0.2	1	0
Lignite_2020	LIGNITE	0.37	0.34	0.5	8	8	0.125	13	4
Lignite_2030	LIGNITE	0.41	0.38	0.5	8	8	0.125	13	4
Nuclear_2020	NUCLEAR	0.39	0.36	0.5	12	10	0.125	20	4
Nuclear_2030	NUCLEAR	0.39	0.36	0.5	12	10	0.125	20	4
PumpHydro_2020	Electricity	1	1	0	0	0	0.4	0	0
PumpHydro_2030	Electricity	1	1	0	0	0	0.4	0	0

4 SCENARIO DEFINITION

4.1 Overview

The market rule parameters that directly influence the functioning of the internal European electricity market with a large amount of wind power are

- the flexibility of rescheduling of dispatch decisions (time dimension),
- the flexibility of the cross-border exchange (time + spatial dimension) and
- the available interconnector capacity (constraints).

The first two parameters are market design parameters. A high flexibility of rescheduling of dispatch decisions will be required when demand and generation are subject to frequent and significant unexpected changes during the day. Flexibility is introduced by generation units with short activation times, e.g., combined cycle gas turbine units or reservoir hydro units. Regarding the second parameter, high flexibility of cross-border exchange is beneficial for market harmonisation. With increasing share of variable generation, flexible cross-border exchange mechanisms contribute to optimising the dispatch on international instead of on national level. As illustrated in Section 7.2, the efficiency of cross-border exchange also depends strongly on the mechanism for capacity allocation. Ideally, capacity is allocated in an implicit way via market coupling mechanisms rather than by an explicit auction. However, since the available market models assume perfect markets, a market simulation including the imperfections of explicit auctioning is not possible.

The third parameter, the available interconnector capacity, is purely technical. It reflects the degree to which the countries are interconnected. Today the interconnector capacity for some important borders is constrained which leads to a limitation of possible exchanges. In the future, grid upgrades and improved congestion management may lead to higher available capacities for cross border exchange. We can, for example, assume the ideal unconstrained case of Europe as a copper plate, or another case where all reinforcements proposed by the Trans-European Networks action will have been realized. This parameter is not a market parameter but rather a boundary condition or constraint for the market simulation work.

In a given energy economic context we can define a multitude of cases within these coordinates, defined by flexibility of rescheduling, flexibility of cross-border exchange and the available interconnector capacity (Figure 3). Parametric studies with the different cases show in how far the markets benefit from a better market framework in terms of these three dimensions. The energy economic context is defined by the electricity demand, the generation mix including the overall wind power share and the prices of fossil fuel and CO_2 emission allowances.

Calculations for the different cases return socio-economic quantities like the operational costs of power generation, that reflect the value of different cases for society, and business-related quantities that reflect the potential value from the viewpoint of a market participant.

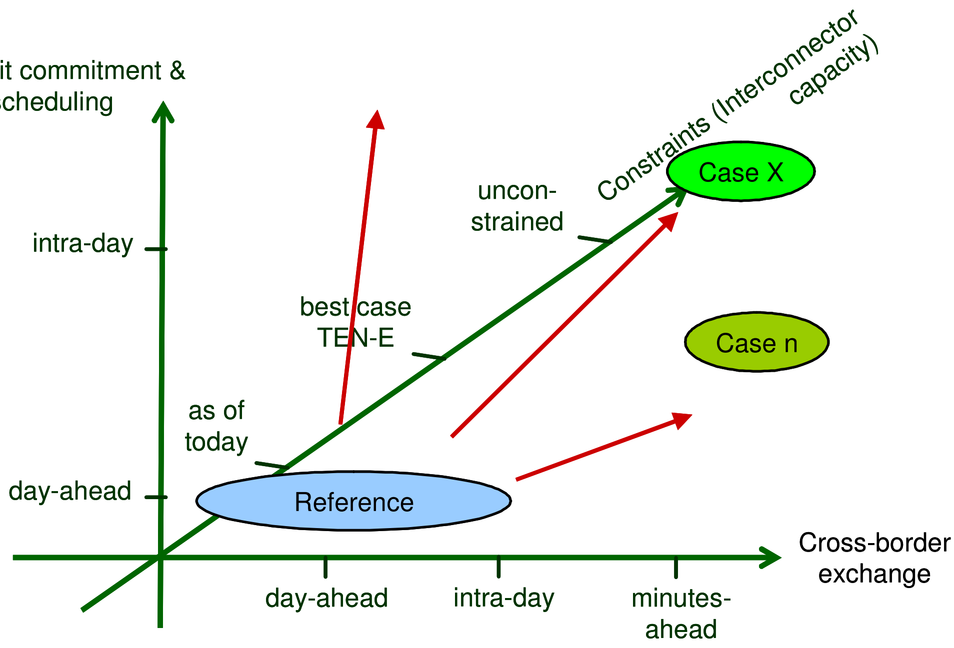


Figure 3: Cases for market simulation as a function of two criteria and the constraints of interconnector capacity

4.2 Cases under Study

The models of the European power market as developed for the Wilmar Planning Tool and for Prosym (see Section 3.6) have been run for different cases. The aim is to:

- simulate the effect of different combinations of market rules in the dimensions listed above
- calculate macro-economic and techno-economic market indicators based on the results of these simulations

The cases were selected taking into account the specific capabilities of the available simulation tools Prosym and Wilmar. The different cases are listed in Table 11.

For the two modelling tools, the wind power scenarios, electricity demand, fuel prices, CO_2 costs and transfer capacity values between countries are the same. The assumptions can differ slightly depending on the level of detail with which the generation portfolio is modelled, but also the treatment of reserves and possibilities for rescheduling. The calculations with Prosym cover 18 European countries with a detailed dataset. Sweden, Finland, Luxemburg, the island of Ireland, the Baltic countries and the countries of East and South-East Europe are not included The calculations with Wilmar cover 25 countries excluding the Baltic countries, Malta and Cyprus. The results from both tools are quantified by a consistent set of indicators.

Table 11: Cases for simulation

Case	Unit commitment / reserve req.	Cross-border exchange	NTC constraints	Energy economic context
Wilmar AllDay2020	day ahead rescheduling	day ahead rescheduling	base 2020	scenario 2020, medium wind
Wilmar ExDay2020	intra-day rescheduling	day ahead rescheduling	base 2020	scenario 2020, medium wind
Wilmar AllInt2020	intra-day rescheduling	intra-day rescheduling	base 2020	scenario 2020, medium wind
Wilmar AllIntExRes 2020	intra-day rescheduling	intra-day rescheduling & exchange of reserves	base 2020	scenario 2020, medium wind
Wilmar AllDay2030	day ahead rescheduling	day ahead rescheduling	best 2030	scenario 2030, medium wind
Wilmar ExDay2030	intra-day rescheduling	day ahead rescheduling	best 2030	scenario 2030, medium wind
Wilmar AllInt2030	intra-day rescheduling	intra-day rescheduling	best 2030	scenario 2030, medium wind
Wilmar AllIntExRes 2030	intra-day rescheduling	intra-day rescheduling & exchange of reserves	best 2030	scenario 2030, medium wind
Prosym d-1 base NTC	Hourly rescheduling	Implicit exchange	base 2020	scenario 2020, medium wind
Prosym t-3 base NTC	Hourly rescheduling	Implicit exchange	base 2020	scenario 2020, medium wind
Prosym d-1 best NTC	Hourly rescheduling	Implicit exchange	best 2030	scenario 2020, medium wind
Prosym t-1 best NTC	Hourly rescheduling	Implicit exchange	best 2030	scenario 2020, medium wind
Prosym Wind 2008	Hourly rescheduling	Implicit exchange	base 2020	scenario 2020, but wind 2008
Prosym 200% Fuel Prices	Hourly rescheduling	Implicit exchange	base 2020	scenario 2020 but with doubled oil & gas prices, medium wind
Prosym Wind must run	Hourly rescheduling	Implicit exchange	base 2020	scenario 2020, medium wind, must-run status for wind power

Figure 4 places the different scenarios that were simulated into a co-ordinate system of spatial dimension, time dimension and technical constraints. The scenarios Wilmar AllIntExRes2020 and

Prosym t-3 Base NTC are comparable and can be considered the most likely for the coming five to ten years. The figure does not show the sensitivity analysis of installed wind power capacity, fuel prices or the possibility of wind power curtailment that were simulated with Prosym.

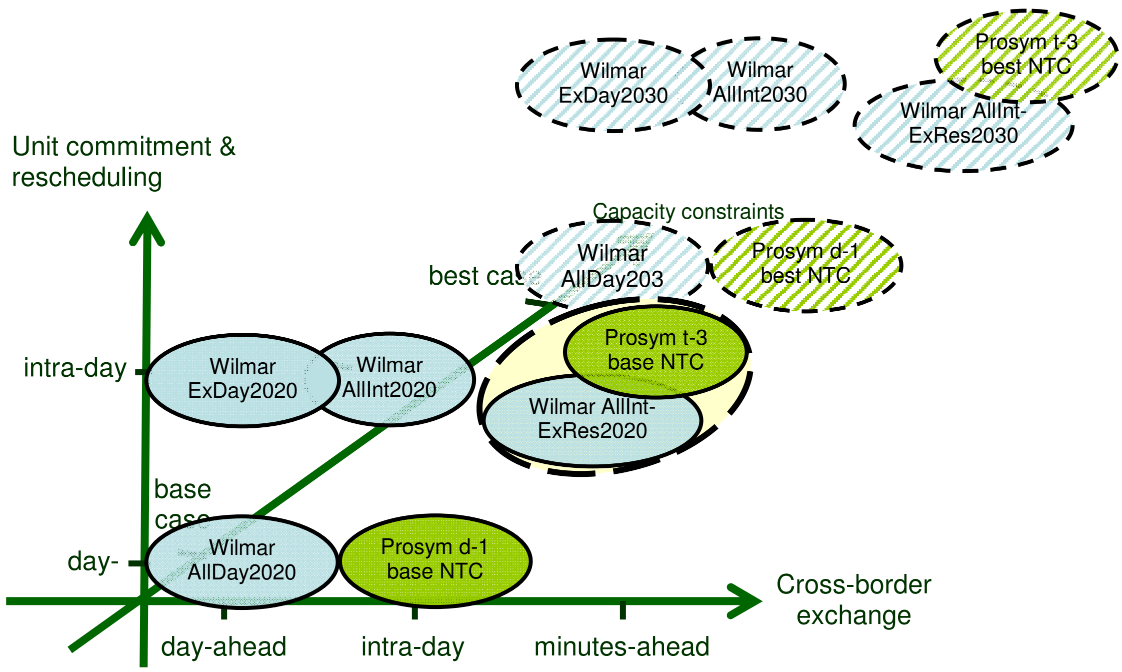


Figure 4 Scenarios for market simulation in terms of spatial dimension, flexibility for rescheduling and capacity constraints

The different cases calculated with Wilmar range from inflexible power markets only performing day-ahead scheduling of unit commitment of slow units and power exchange (AllDay in Figure 4), to intra-day rescheduling of unit commitment but still day-ahead scheduling of power exchange (ExDay), to intra-day rescheduling of both unit commitment and power exchange (AllInt), and finally intra-day rescheduling combined with possibility of exchanging reserve power across borders (AllIntExRes). Thereby four cases have been calculated for each of the scenario years 2020 and 2030.

The calculations with Prosym cover four cases for the target year 2020, characterized by different degrees of connectivity between countries and by differences in gate closure from day-ahead to intra-day, including the possibility for cross-border transfer of reserve power. The gate-closure is reflected by assumptions on the wind power forecast error and the associated requirements for spinning reserves. In addition, the sensitivities have been checked with Prosym for the following three parameters: wind energy penetration level, fuel prices, and wind power curtailment strategy.

4.3 Specific Scenario Definitions

Prosym

While power plant prescheduling in Prosym is set on weekly basis, the generation units can be rescheduled every hour. Power plants are dispatched hourly based on their availability and technical capabilities. Per default, wind energy is considered as an economical plant with maximum installed capacity equal to the hourly profile of realised wind generation. This means, wind power generation can be curtailed if economically indicated. The modelling of gate closure for TradeWind, in Prosym, is based on the non-spinning reserve necessary to cover the wind power variation. Shorter gate closure implies an updated forecast closer to real time and, consequently, a lower demand of spinning reserves. The following gate closure times have been considered in the Prosym calculations:

- gate closure 24 hours ahead (Day-1) and
- gate closure 3 hours ahead (t-3).

Combining day-ahead and intra-day gate closure with the different NTC scenarios (Appendix 2) yields four cases for simulation:

1. Base case NTC, Wind forecast (Day-1)
2. Base case NTC, Wind forecast (t-3)
3. Best case (high) NTC, Wind forecast (Day-1)
4. Best case (high) NTC, Wind forecast (t-3)

All four cases were run with wind power installed capacity for 2020 (medium), electricity demand for 2020 and energy economic boundary conditions for 2020 as given in Section 3.

No Prosym scenario was run for the 2030 wind power scenario. Instead, the sensitivity of market outcomes was assessed by simulating three additional cases, namely:

5. Case 1, however, with wind power installed capacity for 2008 (medium)
6. Case 1, however, with oil and gas prices doubled as compared to the 2020 prices listed in Table 2,
7. Case 1, however, wind power is must-run generation.

Wilmar

With Wilmar, simulations were carried out for two target years characterized by installed wind power capacity, electricity demand, available interconnector capacity and energy economic boundary conditions:

- 2020 with medium installed wind power capacity scenario and base case NTC.
- 2030 with medium installed wind power capacity scenario and best case (high) NTC.

For each target year, the 4 model runs were carried out, yielding eight model runs for Wilmar in total. These four different cases investigate the consequences of having different degrees of market integration between countries and having different amounts of well functioning intra-day power markets for the operation of the European power market in terms of operational costs of power generation, CO_2 emissions and power market prices:

1. AllDay: Unit commitment for slow units and power exchange over borders determined day-ahead (12-36 hours ahead) and not rescheduled intra-day. The dispatch (production levels) of the committed units can be changed intra-day subject to the minimum and maximum operation levels. No exchange of replacement reserves across borders. Slow units are units with a start-up time of one hour or more, i.e. all units except hydropower with reservoir, pumped hydro storage, units using light oil or fuel oil. This scenario is not realistic; however, it serves as a worst-case bottom line.
2. ExDay: Like AllDay except for unit commitment for slow units now being rescheduled intra-day. Cross-border exchange is still allowed day-ahead only.
3. AllInt: Like ExDay but power exchange allowed to be rescheduled intra-day.
4. AllIntExRes: Like AllInt but exchange of replacement reserves across borders allowed, i.e. part of the demand for replacement reserves can be provided by a neighbouring country by reserving part of the available cross-border transfer capacity or this purpose.

AllDay is an extreme scenario modelling a power market with very inflexible market rules, and very badly functioning intra-day markets. Both unit commitment for slow units and cross-border exchange are determined day-ahead creating problems with handling the deviations between day-ahead production plans and real-time operation created by the day-ahead forecasts errors of load and wind power production. In ExDay replanning of day-ahead unit commitment decisions is possible, i.e. either well-functioning national intra-day power markets are in place or the TSO do the rescheduling. Still usage of cross-national transmission lines is fixed day-ahead and exchange of reserves across borders is impossible. In AllInt the countries cooperate in covering deviations between day-ahead production plans and real-time operation by allowing the cross-border power exchanges to be rescheduled intra-day. Finally in AllIntExRes even replacement reserves (minute to hour reserves) can be exchanged across borders.

Unlike with Prosym, here, no cases with explicit differences in wind power forecast quality have been calculated. However, the forecast quality is reflected by the varying demand for rescheduling in the different branches of the Wilmar scenario tree. Hence, the reducing forecast error while approaching real time is reflected by the reduced need for rescheduling.

Hence, the eight model runs cover two scenarios of input data assumptions corresponding to year 2020 and 2030. The four model runs in each input data scenario therefore share exactly the same assumptions concerning production costs, power plant capabilities, installed capacities, etc. They only deviate in the assumptions concerning the possibilities for intra-day rescheduling of unit commitment and power exchange, and the ability to share reserves across borders.

5 MARKET INDICATORS FOR PRESENTATION OF RESULTS

5.1 Conventions and Definitions

In order to allow for a consistent interpretation of the market simulation results with the different tools and for the different scenarios a set of market indicators has been defined for presentation of the results.

The definitions of indicators below are derived from discrete time series of market data as follows, resulting from the simulations. We suppose that one dataset of results is a discrete time series of hourly values

$Y = \{y_1, y_2, ..., y_i, ..., y_N\}$, (2)

where $i = 1, 2, ..., N$=8760.

The variable Y refers to results of market simulations for one market zone/country being either an average power over one hour or a price that is valid for this hour. Other data sets would be

$P = \{p_1, p_2, ..., p_i, ..., p_N\}$ (3)

or

$Q = \{q_1, q_2, ..., q_i, ..., q_N\}$, (4)

where P refers to prices or costs and Q to quantities of power.

The time coordinate is

$X = \{x_1, x_2, ..., x_i, ..., x_N\}$ = {1h, 2h, ..., 8760h}. (5)

Based on these datasets we define different indicators as follows:

Duration Curve

Duration curves are derived by sorting Y in descending order of y_i. With the discrete time X set out on the ordinate, the abscise indicates the value y that is exceeded during the corresponding time x.

Mean Value

The mean value μ of the time series Y is calculated as

$$\mu = \frac{1}{N}\sum_{i=1}^{N} y_i \,. \qquad (6)$$

Standard Deviation

The standard deviation σ of the time series Y is calculated as

$$\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(y_i - \mu)^2} \,. \qquad (7)$$

Maximum and Minimum value

The maximum y_{max} and minimum y_{min} of the time series Y are calculated as
y_{max}, = max{Y} (8)

and

y_{min} = min{Y}. (9)

Weighted Average of Clearing Price (WACP)

For a given type of generation with quantities in *Q*, the weighted average *w* of the clearing price *P* is calculated as

$$w = \frac{\sum_{i=1}^{N} p_i q_i}{\sum_{i=1}^{N} q_i}. \tag{10}$$

The WACP for a given generator type shows the price that will be paid on average for energy from this type of generator.

The indicators are explained in the following section.

5.2 Socio-economic Indicators

Generation Mix per Fuel

In the market models, the procured generation at every hour can be split per fuel type.

Operational Costs of Power Generation

The operational costs of power generation are the overall operational costs of the power generation portfolio in the system under study. Both Prosym and Wilmar calculate the operational costs of power generation as the sum of fuel costs including start-up fuel consumption, start-up costs, costs of consuming CO_2 emission allowances, fixed and variable operation & maintenance costs. Energy not served and reserve deficiencies are reported separately. With Prosym, energy not served was accounted for at a value of 275 €/MWh, reflecting the generation cost of an open cycle gas power plant. With Wilmar, costs of not meeting spinning reserve and replacement reserve targets are valued to 300 Euro/MWh. The value of lost load, in Wilmar, is accounted for separately at 3000 Euro/MWh, reflecting possible penalties for loss of load.

For each simulated hour a value for the generation cost during the hour is calculated for the entire system under study. It is based on the generation mix for each hour and the associated costs. The annual sum of generation costs reflects the socio-economic cost of power generation for the whole system.

Import and Export

Import and export can either be a result of physical generation capacity deficit/excess or economics, i.e., generation readily available, but more expensive than in the neighbouring zones, and thus less used).

5.3 Business-related Indicators

Wholesale Power Prices

The wholesale power price is the market clearing price that results from matching supply and demand. In the market models it is assumed to be equal to the marginal price of the marginal generation unit. This price is further referred to as *power price* or just *clearing price*. For each simulated hour a market clearing price is calculated. It is based on the generation mix for each hour and the associated costs.

Power prices can be calculated for the different markets (day-ahead or intra-day) and for different countries. While interconnection capacity is available (not constrained), two neighbouring countries will have equal clearing price. When the interconnection is fully loaded, so-called market splitting is applied and the prices can differ.

In the analysis, duration curves and average clearing prices are shown. Moreover, minimum, maximum and standard deviation of market clearing prices are shown in order to give an impression of the variability and volatility of the prices.

Market Value of Generation

The market value of power generation from a given source is reflected by the weighted average clearing price (WACP), weighted with the amount of power that is procured from this source for each hour. Consequently, the market value of wind power is calculated as weighted average of the market clearing price with the generated amounts of power from wind energy. It reflects the income of the generator.

Here, the weighted average prices have been calculated over one year.

Curtailment of Wind Power or Load

Wind power has costs near to zero which means that it is running all the time expect when curtailed. Curtailment would usually occur only in case of contingencies in the grid. However, with large wind power penetration, situations may regularly occur where curtailment of wind power generation would be economically beneficial compared to further limiting the output of conventional must-run units.

6 RESULTS AND DISCUSSION

6.1 Prosym

6.1.1 Socio-economic Results

Operational Costs of Power generation and Market Parameters

The operational cost of power generation (system costs) for the 18 countries included in the Prosym model have been calculated from the hourly Prosym results. They are listed in Table 12, together with the market indicators defined in Section 5.1, for the different cases as defined in Section 4 .

Table 12. Operational costs of power generation (system costs) as calculated with Prosym for the system consisting of 18 countries (system costs in M€/year, other amounts in M€/hour)

Sc. No.	System costs 2020 (M€)	Total system costs (M€)	mean value (M€/h)	std.deviation (M€/h)	minimum (M€/h)	maximum (M€/h)	average (€/MWh)
Sc.1	base NTC, D-1 (day ahead)	108.394	12,4	3,4	5,4	21,0	31,55
Sc.2	base NTC, t-3 (3h ahead)	108.132	12,4	3,4	5,4	20,9	31,48
Sc.3	high NTC, D-1 (day ahead)	108.249	12,4	3,3	5,5	20,9	31,49
Sc.4	high NTC, t-3 (3h ahead)	107.989	12,4	3,3	5,5	20,8	31,42
Sc.5	Sc.1 + wind 2008	119.190	13,6	3,5	6,7	22,0	34,88
Sc.6	Sc.1 + oil and gas * 200%	133.213	15,2	4,3	6,1	27,2	38,78
Sc.7	Sc.1 + wind 2020 must run	108.419	12,4	3,4	5,4	21,0	31,51

The operational costs of power generation in Table 12 are annual values in millions of euros per year, except for the last column, i.e., the average system costs calculated as total system costs in 2020 divided by total production (MWh) in 2020[9].

For the wind modelling in both *base case NTC* and *best case (high) NTC* scenarios, a forecast made 24 hours ahead (D-1) and 3 hours ahead (T-3) has been considered. The resulting operational costs of power generation for the different wind forecast qualities quantify the added value of allowing for rescheduling of reserves until close to real time along with a better wind forecast quality. For the base case NTC scenario, the operational costs of power generation are 0.24% or 262 million € higher with gate-closure day-ahead than with gate-closure 3 hours ahead. However, although this difference is relatively small (perfect market simulation), in the real market the clearing prices are higher and the socio-economic savings associated with possibilities for more flexible rescheduling can be significantly higher.

With better connectivity between the countries (best case (high) NTC values as compared to base case NTC values), the total operational costs decrease by 0.13% or 145 million € for gate closure 3 hours ahead.

Energy-economic Sensitivity of Operational Costs of Power Generation

In case no additional wind capacity will be built up to 2020 (i.e., wind installed capacity in 2020 is equal to wind installed capacity in 2008, Scenario 5) the operational costs of power generation will be about 10% or 10.8 billion € higher than in Scenario 1. The difference reflects the macroeconomic value of wind power as a generator requiring no fuel. In other words, the 128 GW of wind power to be installed between 2008 and 2020 in the 18 countries under consideration, is worth for almost 10% of savings in operational costs of power generation each year as from 2020 with the standard fuel price scenario. With an average capacity factor of 23% for wind power in the 18 countries considered in this comparison, the macro- economic cost savings of wind power are then 42 €/MWh. As comparison, the average support to wind power in these European countries lies around 70 €/MWh

[9] Here energy not served and reserve deficiencies have been included in the total system costs

in 2006[10], but are expected to reduce in the coming years. This implies that wind power recovers a large part of its social support by reducing the operational costs of power generation.

With the wind power medium scenario for 2020, but oil and gas prices doubling as compared to the 2020 baseline scenario (Scenario 6), the operational costs of power generation will be about 25 billion € higher than in Scenario 1. In this case, increase of the socio-economic value of fuel-free generation would be accordingly.

Curtailment of wind power has no significant effect on the operational costs of power generation as it rarely occurs. In case Sc. 7 wind is modelled as must run unit (no curtailment is allowed). In a perfect market and when no internal bottlenecks are considered, not curtailing wind power production will result in higher operational costs, as conventional power plants need to be shut down and by that will increase the operational costs with their extra start-up costs. However, one should keep in mind that this result does not reflect the real market where local congestion of the grid demands for wind curtailment.

The sensitivity analysis shows that the overall fraction of wind power in the generation mix and the cost of fuel for conventional power generation are the decisive parameters for the overall operational costs of power generation. Also the optimisation of market rules allows realizing additional gains in market efficiency.

Import and Export

The import and export values for *base and additional MW for best case (high) NTC in 2020 are presented below in* Table 13.

Table 13: Differences in NTC values between base case NTC 2020 and best case (high) NTC 2030.

Countries		**Country codes**		**Base NTC**		**additional for Best NTC** (values to be considered in addition to Base NTC)	
Country A	Country B	Country A	Country B	NTC A to B [MW]	NTC B to A [MW]	NTC A to B [MW]	NTC B to A [MW]
Denmark-West	Norway South	DKW	NO	1.450	1.450	600	600
Denmark-West	Denmark-East	DKW	DKE	600	600	600	600
France	Italy	FR	IT	2.650	995	1.000	1.000
France	Great Britain	FR	GB	2.000	2.000	2.000	2.000
Germany	Denmark-E	DE	DKE	550	550	550	550
The Netherlands	Norway South	NL	NO	700	700	700	700

For the scenarios *Base case NTC, Wind forecast D-1* and *best case (high) NTC, Wind forecast D-1* the energy exchange volumes by country are presented in Figure 5 and Figure 6.

As not much additional cross-border capacity is considered in the best NTC case compared to the base NTC case (see Table 13) and also just for a few countries, there are no significant changes in the import-export balance of most countries. France and Germany will remain net exporters while the Italy will remain net importer of electricity. Nevertheless, a significant increase of power exchange can be observed for those countries that today are connected only to a limited extent and for which large increases in interconnection capacity are foreseen in TradeWind WP6. The difference is especially significant with regard to imports into Italy and into Great Britain.

[10] M.I. Blanco and G. Rodrigues (2008) Can the future EU ETS support wind energy investments? Energy Policy 36. 1509 – 1520.

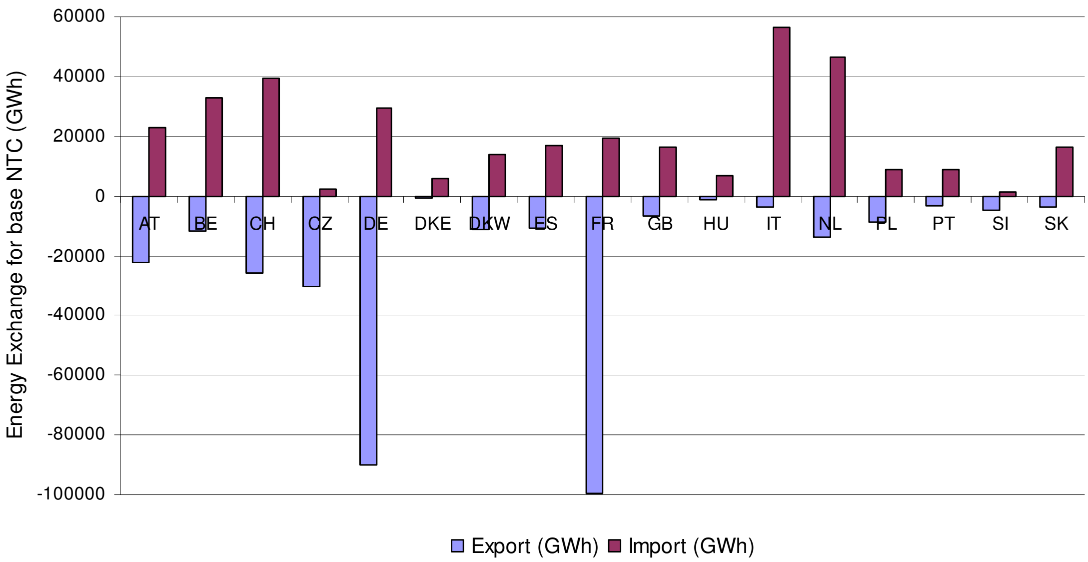


Figure 5. Annual energy exchange between countries for the base case NTC scenario (gate closure at D-1, wind power2020 medium and scenario parameters for 2020)

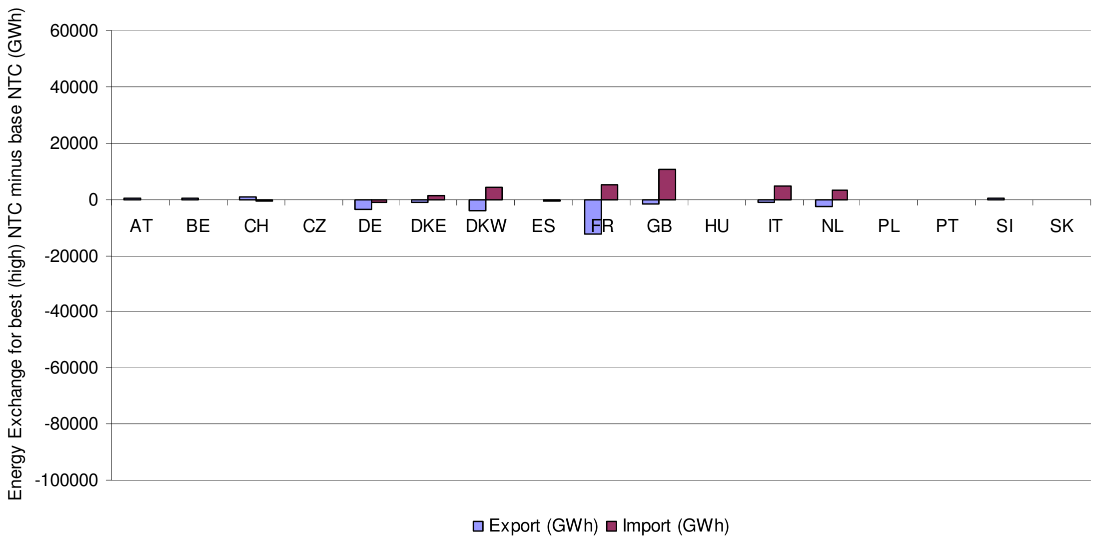


Figure 6. Annual energy exchange between countries for the best case (high) NTC scenario (gate closure at D-1, wind power2020 medium and scenario parameters for 2020)

6.1.2 Business-related Results

Wholesale Power Prices

Wholesale power prices in the form of market clearing prices have been calculated with Prosym as marginal costs of the marginal unit, assuming a perfect market and optimal allocation of interconnection capacity to the market.

The clearing prices of a number of countries are presented in Figure 7 as duration curves for the 2020 medium wind, base case NTC, Day-1 (Scenario 1).

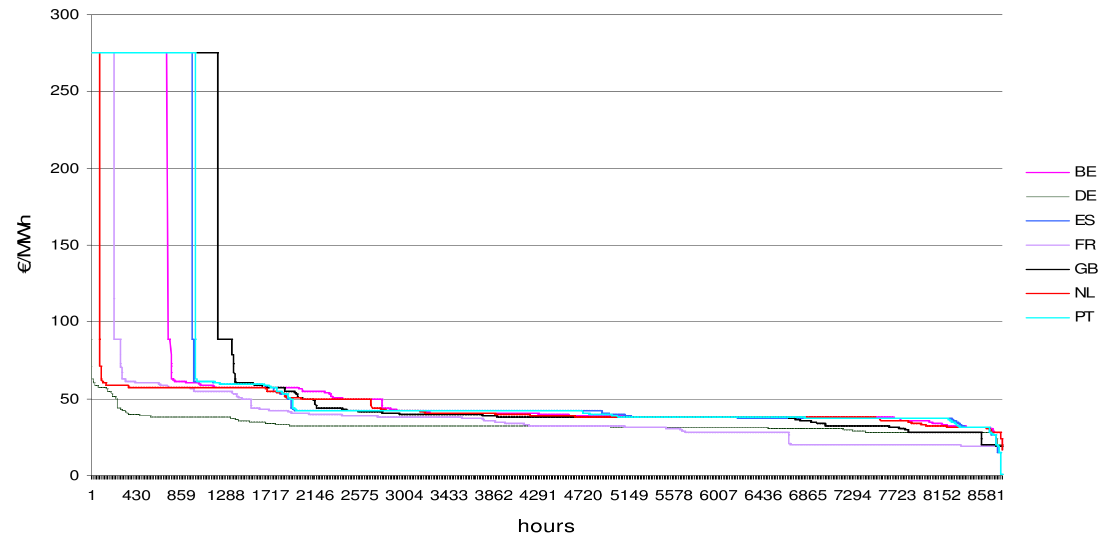


Figure 7 Duration curves of clearing prices for 2020 medium wind, base NTC, D-1

In order to evaluate the sensitivity of the clearing prices with regard to gate closure and interconnectivity, differences of the clearing prices for the seven scenarios considered in Section 4.2 have been calculated. The differences in mean values of hourly clearing prices in 2020 are presented in Table 14. A more elaborated overview is given in table 16, Appendix 3.

Table 14 The differences in mean values of clearing prices, 2020 scenarios

Differences in mean values of Clearing price in a perfect market in €/MWh (Calculations based on hourly Prosym Output)																
Scenarios 2020	**AT**	**BE**	**CH**	**CZ**	**DE**	**DKE**	**DKW**	**ES**	**FR**	**GB**	**HU**	**IT**	**NL**	**PL**	**PT**	**SI**	**SK**
Sc.1 min Sc.2	-0.29	-0.66	-0.40	-0.09	-0.14	-0.13	-0.14	-0.11	-0.64	-0.77	-0.12	-0.25	-0.27	-0.12	-0.08	-0.19	-0.11
Sc.3 min Sc.4	-0.29	-0.35	-0.18	-0.08	-0.14	-0.14	-0.14	-0.08	-0.41	-0.49	-0.10	-0.27	-0.19	-0.13	-4.29	-0.22	-0.10
Sc.1 min Sc.3	0.28	0.51	0.47	-0.06	-0.13	1.16	-0.19	-0.05	-1.15	4.10	-0.03	0.39	0.71	-0.04	-0.01	0.47	0.01
Sc.2 min Sc.4	0.27	0.82	0.69	-0.04	-0.12	1.15	-0.20	-0.01	-0.92	4.38	-0.01	0.37	0.79	-0.06	-4.22	0.43	0.02
Sc.1 min Sc.5	-2.14	-12.57	-7.97	-1.92	-2.36	-3.30	-2.92	-13.72	-12.86	-16.18	-0.58	-1.24	-4.99	-1.92	-14.71	-1.30	-0.65
Sc.1 min Sc.6	-22.30	-27.30	-20.81	-4.26	-4.85	-8.48	-7.25	-25.29	-14.27	-20.71	-26.33	-25.97	-28.94	-5.32	-25.00	-25.37	-26.35
Sc.1 min Sc.7	0.00	-0.01	0.03	0.00	0.00	0.03	0.00	0.00	0.00	-0.01	-0.01	0.01	0.00	0.00	0.00	0.02	-0.01

Influence of Gate Closure and Forecast Error

Average market clearing prices with gate closure intra day are generally little higher than those for gate closure day ahead (Sc.1 min Sc.2, and Sc.3 min Sc.4). As a lower wind power forecast error in Prosym is reflected by a lower demand for spinning reserves, gate closure intra-day allows to run the operational generation units at higher load as compared to the day ahead gate closure. Consequently, the price, as derived from the cost of the marginal megawatt-hour, is slightly higher. In practice, this increase in price would be compensated by the reduced amount of spinning reserves.

Influence of Available Transfer Capacit

In contrast to the clearing price, the degree of connectivity, i.e., base case NTC versus best case (high) NTC (Sc.1 min Sc.3 and Sc.2 min Sc.4)., affects the market prices much stronger, especially for those countries where the NTC in the base case limits the power exchange with their neighbours. For countries like Great Britain, Belgium, the Netherlands, Denmark East or Italy, which are net importers, an increased connectivity leads to significantly lower electricity prices. Conversely, for net exporters like France and Germany prices may increase, although less pronounced. The variability of wholesale prices, represented by the standard deviation, decreases significantly for many countries when the connectivity is improved (see Appendix 3,). This leads to a conclusion that increased interconnectivity can offer a hedge against wholesale price shocks by limiting the impact of events such as unavailability of generation capacity or ability to use dominant market position (i.e. market power).

Influence of Oil and Gas Prices

Finally, the increase in oil and gas prices and the overall installed wind power capacity have a very strong impact on the power prices. High oil and gas prices lead to higher marginal costs for oil and gas-driven units and, hence, to higher clearing prices. In most countries, the 2020 clearing prices would increase by 20 to 30 €/MWh when the oil and gas prices double. The duration curve of the average operational costs of power generation of the 18 countries considered in the Prosym simulation are presented in Figure 8.

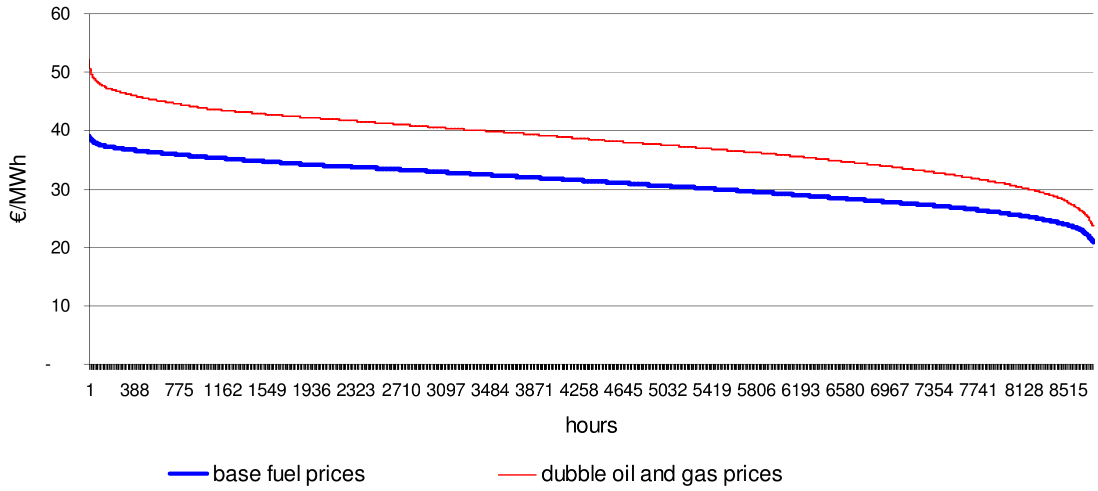


Figure 8: Duration curves of the average operational costs (system costs; base fuel prices against double oil and gas prices)

Influence of Installed Wind Power Capacity

Conversely, the installed wind power capacity contributes to lower operational costs[11] with power at almost zero marginal costs[12]. Comparing the medium scenario for installed wind power in 2020 (Sc.1) with the installed wind power capacity in 2008, while keeping load, conventional generation and NTC values the same as in the case of 2020 (Sc.5), exhibits clearing price differences in the range of several euros per megawatt-hour, depending on the specific generation mix in the country (see Figure 9, which represents the duration curves of the clearing price in Great Britain). The countries that benefit most of increased wind capacity are Great Britain, Portugal, Spain, France and Belgium (see Table 14, Sc.1 min Sc.5).

More duration curves of the market clearing price are available in Appendix 3 for Belgium, Germany, Spain, France, Great Britain and the Netherlands.

[11] Operational costs are equal to system costs divided by the amount of electricity produced

[12] Operation and maintenance costs have been considered

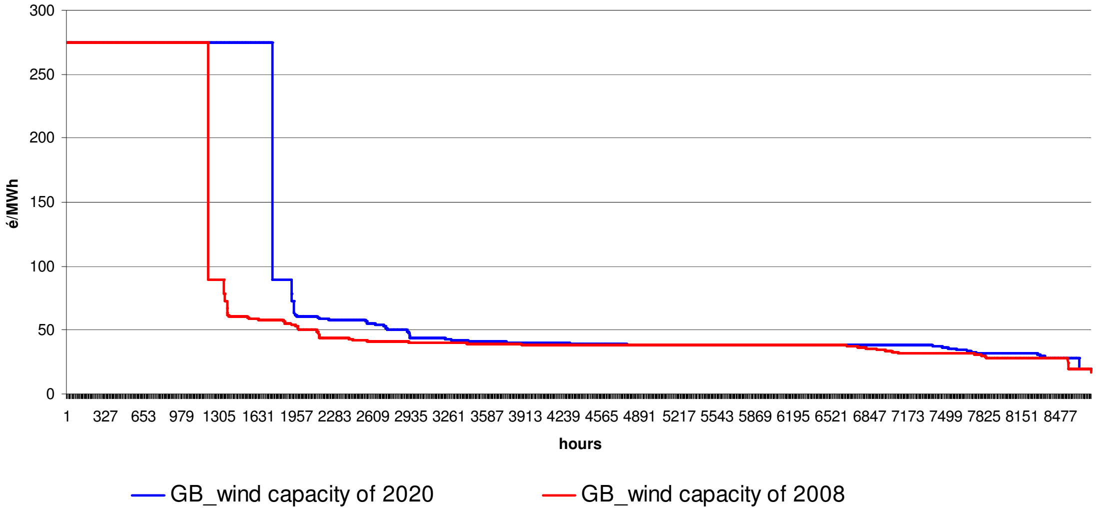


Figure 9 The d*uration curves of clearing prices for Great Britain (wind installed capacity of 2020 against 2008)*

Market Value of Generation

As wind power is a price taker, the market price at which wind power can be sold on average depends on its availability over time in relation to the clearing price profile. By expressing the results as weighted average clearing prices (WACPs), the value of wind production profile is included. This means, for each hour, the hourly clearing price is weighted with the amount of wind power generated at the hour.

Figure 10 shows the average clearing price of the whole system for the base case NTC, Day-1 scenario compared to the WACP for wind power. The figure shows that the WACP for wind power is equal to the average clearing price in most countries. Spain and Portugal have a lower WACP than the clearing price, which means that the wind is blowing mostly at low price hours.

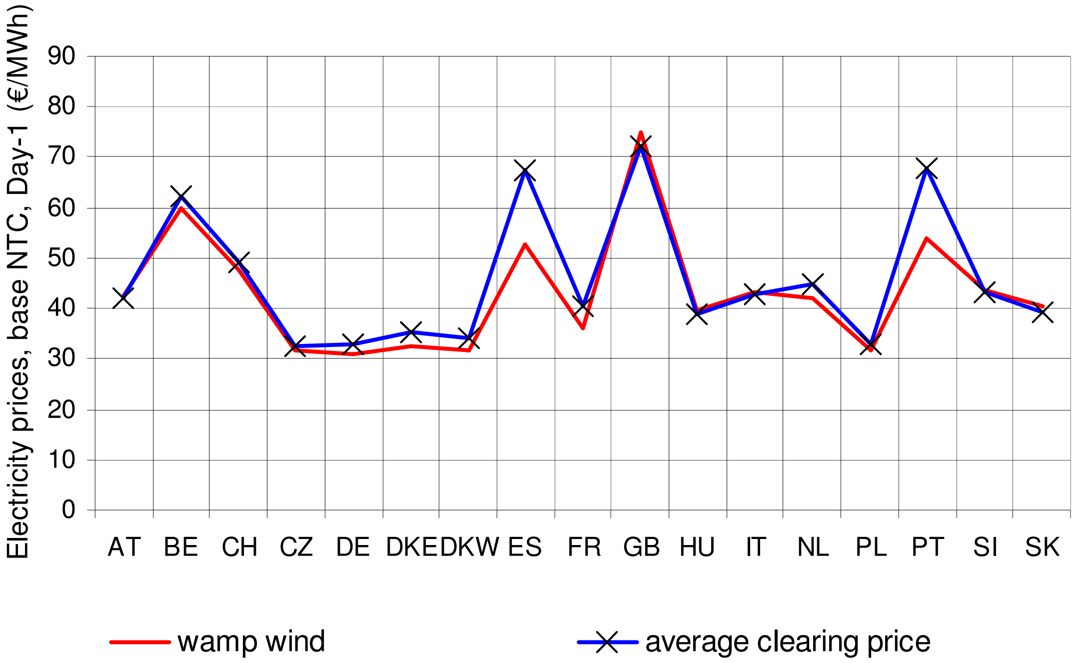


Figure 10: Annual average clearing prices and weighted average clearing prices for wind power per country

The same conclusions follow from examining Figure 11, which represents the ratio of WACP between wind power production and conventional production.

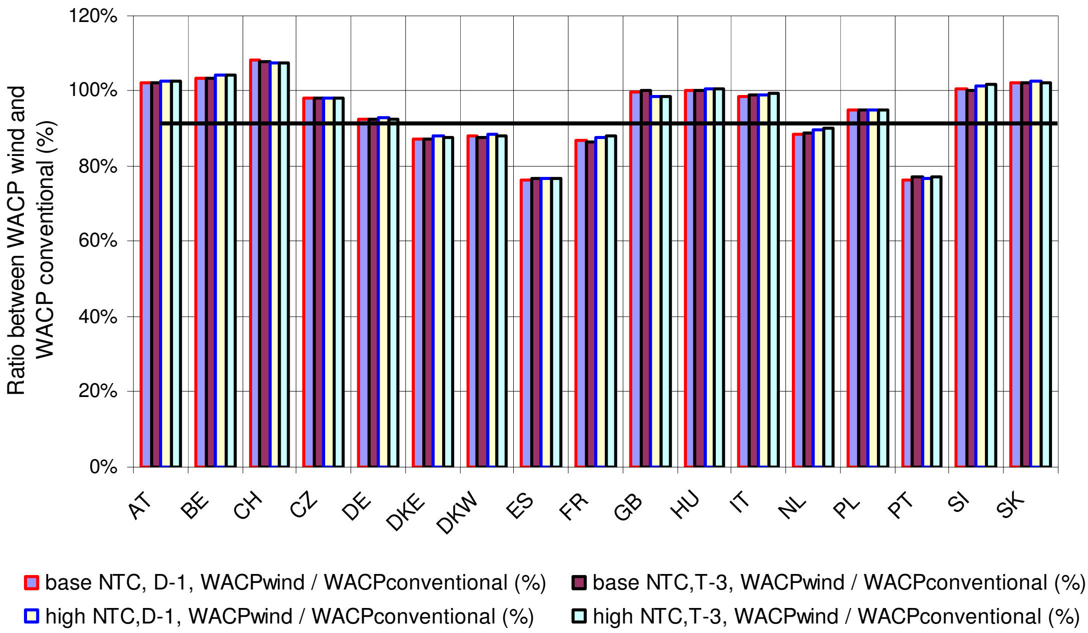


Figure 11: Ratio of weighted average clearing prices for wind energy over WACP of conventional production.

Figure 12 expresses the WACP for wind power production minus the WACP for conventional power production by 2020 (medium wind, Sc.1 to Sc.4), which shows that the difference can increase to -16 EUR/MWh for Spain and Portugal. This implies that these countries have a negative correlation between wind power production and market clearing price. This is remarkable, especially because these countries have a relatively large wind power penetration by 2020.

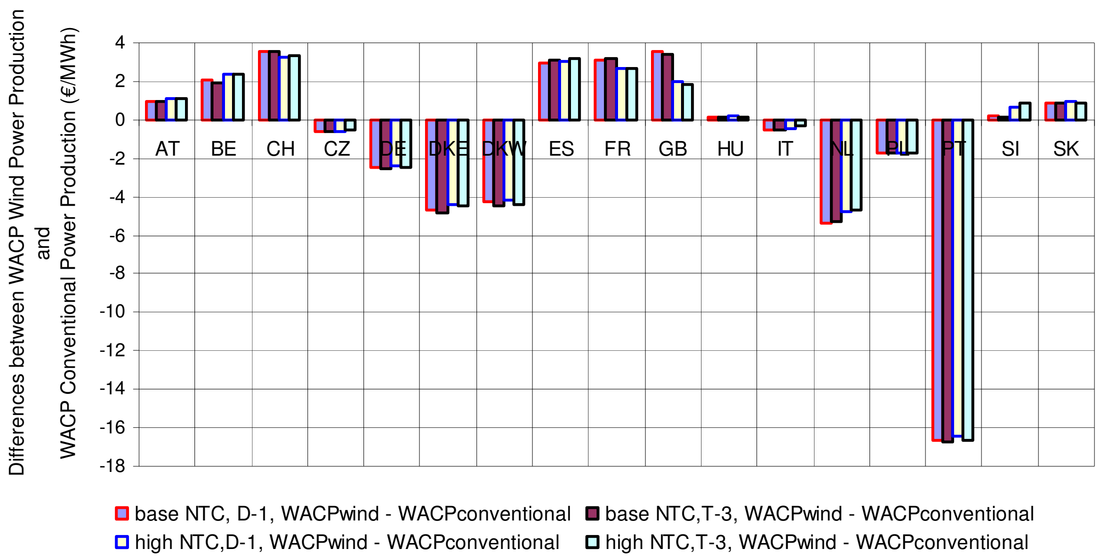


Figure 12. Differences between weighted average clearing price (WACP) of wind power generation minus weighted average clearing price of conventional generation for all countries

In Figure 13, the value of wind power and conventional power is shown next to the ratio of wind power generation to conventional power generation. This figure shows that higher wind penetration will reduce the value of wind power, partly because the chance wind blows during low price hours increases with more wind production (negative correlation between wind penetration and wind value). A same effect can be found in the capacity credit of wind power.

Looking at the whole system, there is no clear trend in the relation between market clearing price and hours of wind production, expect for Spain and Portugal which show a clear negative correlation as mentioned before. Obviously, the value of wind power depends only partly on the wind power penetration but also on the local characteristics of wind speed and power demand, on the overall generation mix and on the continental generation pattern.

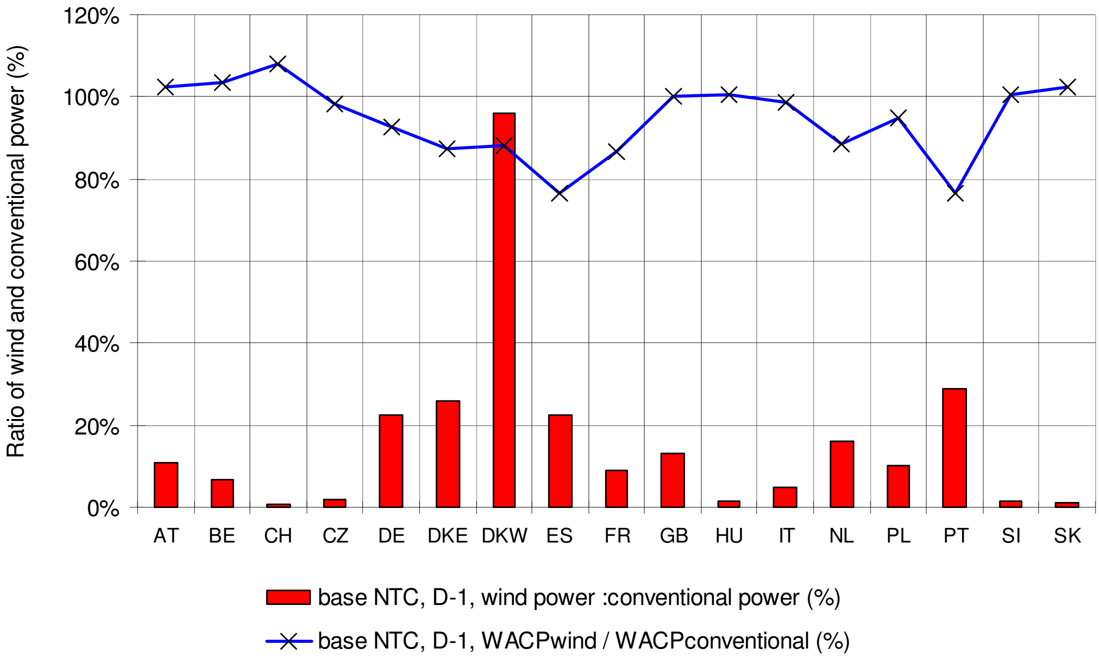


Figure 13. Proportion of wind power to conventional power generation (left axis, in percentages) and differences between weighted average clearing price (WACP) of wind power generation minus weighted average clearing price of conventional generation (right axis, in €/MWh)

Curtailment of Wind Power

In the base case NTC scenario with medium installed capacity for 2020, wind power would be curtailed most of the times when clearing prices are low and constraints are present; only in Spain and Portugal wind is curtailed. The unused wind energy would be 84.9 GWh in Spain and 6.8 GWh in Portugal. The clearing prices during wind curtailment are very low and so are the income losses due to curtailment. The value of curtailed wind energy for 2020 would be 102,000 € per year in Spain and 8,184 € per year in Portugal. For the same scenario, the annual wind power generation in Spain is 69 878 GWh. Hence, the annual wind curtailment volume is only 0.12 % of total annual wind power generation.

As in this model no internal transmission constraints are considered, wind power would be curtailed only in case of reserve obligations that cannot be met or due to constraints on other generation units, e.g., minimum up-time or startup costs. In practice, curtailment will rather happen due to transmission constraints and mostly in case of system contingency.

6.2 Wilmar

6.2.1 Socio-economic Results

Generation Mix per Fuel

Figure 14 shows the installed capacity in the 25 countries covered in the Wilmar model for the two scenario years 2020 and 2030. The fuel Electricity represents unloading of pumped hydro storage. Table 15 and Figure 15 show the resulting yearly electricity production distributed on fuels for all model runs. The share of wind power here is 10.5% in 2020 and 12.5% in 2030. As the assumed demand scenario from Eurelectric is rather conservative especially for 2030 (see Section 3), the wind energy share is lower than, e.g., in the European Commission's 2007 baseline scenario

[Cap08] or EWEA's Pure Power scenarios [Zer08]. The overall annual demand used in TradeWind is shown in . The data per country are listed in Appendix 1.

As today virtually all generators apply intra-day rescheduling, the cases *AllDay2020* and *AllDay2030* do not reflect a realistic situation. The *AllDay* cases rather serve as worst-case bottom line in order to illustrate the importance of flexibility. The results discussed in the following paragraph show how the operational costs of power generation would increase if this flexibility would not be possible.

In the case *AllDay2030*, the value for hydropower production shows a 35 TWh (7%) higher production than in the other 2030 cases (highlighted with red in Table 15). *AllDay2030* can be considered the scenario with the most inflexible market rules along with high wind power generation. The reason for this is that the day-ahead forecast errors in 2030, due mainly to the wind power production in combination with an extremely inflexible market structure, lead to many hours with capacity constrained production schedules and associated very high power prices (as a result of significant reserve obligations needed to accommodate high forecast errors and no rescheduling flexibility). This causes the hydropower reservoir levels to deviate from the historical reservoir level which is followed in the other 2030 cases. The effect is mainly seen in Norway and Sweden with a deviation of 20 TWh and 6.4 TWh, respectively.

If unit commitment would be fixed the day ahead the need of flexible pumped hydro storage (fuelled by electricity) increased as compared to the other cases in 2020 and 2030. Power plants using biomass would still have capacity factors of 0.95-0.96, i.e., they were generating maximum power in practically all hours; the same would apply for nuclear power. When moving from 2020 to 2030, load in the 25 countries under study increases by 478 TWh (see Table 18), wind power production increases by 142 TWh (34%), coal decreases by approximately 44 TWh due to a decrease in the installed capacity of coal (see Figure 14), and natural gas increases by approximately 260 TWh due to an increase in the installed capacity of natural gas units. Generation from lignite increases by approximately 90 TWh although the installed capacity is slightly decreasing from 2020 to 2030. In conclusion, the increase in load would mainly be covered by natural gas production, wind power and lignite. Pumped hydro storage and open-cycle gas turbines (OCGTs) using light oil would used more in 2030 than 2020 due to the increase in wind power production.

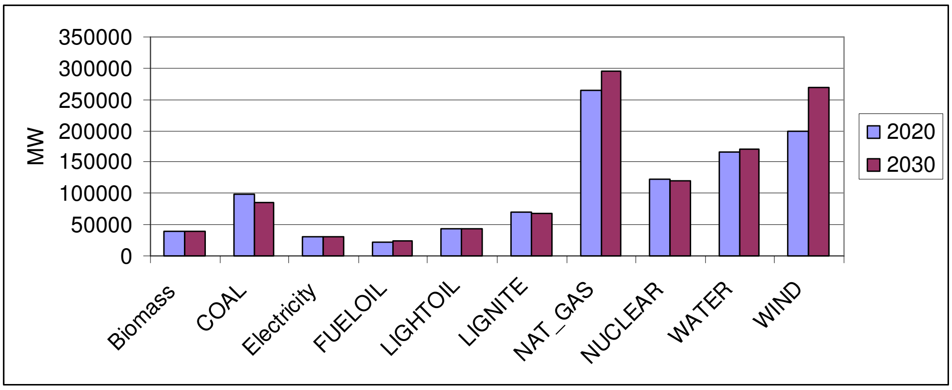


Figure 14. Installed capacity distributed on fuels in 2020 and 2030 for all cases; pumped hydro storage uses the fuel Electricity

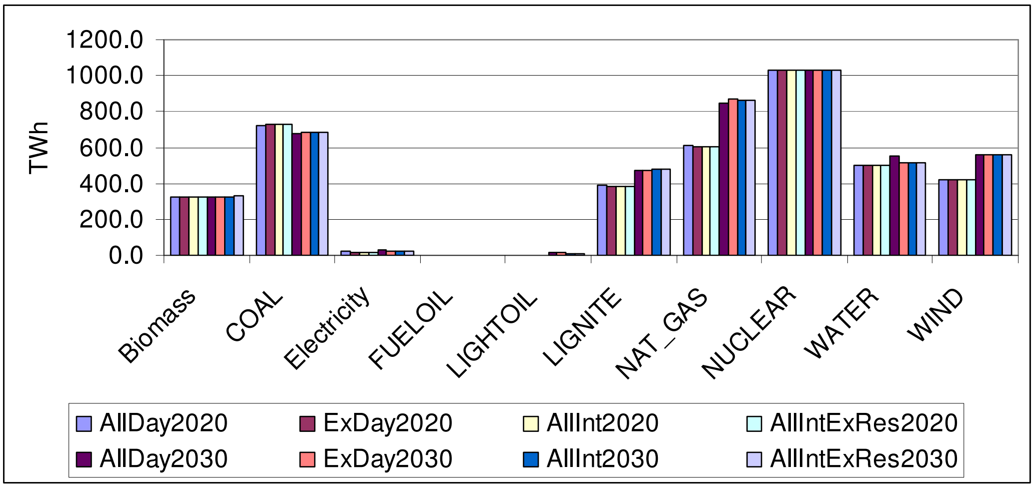


Figure 15. Yearly electricity production distributed on fuels in 2020 and 2030 for all cases.

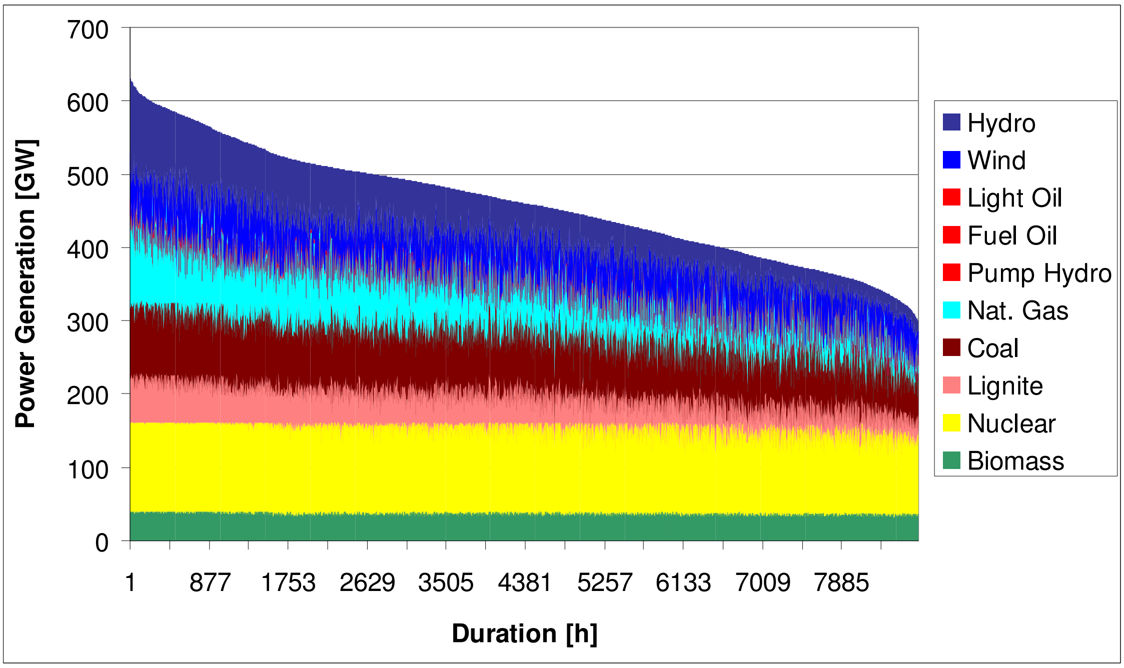


Figure 16. Duration curve of electricity production stacked by fuel type for the ExDay2020 case; calculation with Wilmar covering 25 countries

Table 15 Yearly electricity production in TWh for all countries distributed on fuel types for all model runs in 2020 and 2030; the fuel Electricity represents unloading of pumped hydro storage.

	Biomass	Coal	Electricity	Fuel oil	Light oil	Lignite	Natural gas	Nuclear	Hydro	Wind	Total
AllDay2020	324.3	720.6	19.5	0.6	2.6	388.0	609.5	1032.2	502.0	419.5	4018.9
ExDay2020	325.3	728.8	15.6	1.8	0.8	383.7	604.1	1032.7	502.1	420.2	4015.1
AllInt2020	326.3	730.1	14.1	0.9	0.3	384.2	601.8	1032.8	502.1	420.3	4013.0
AllIntExRes2020	326.7	731.1	14.7	0.8	0.3	384.2	600.8	1032.5	502.2	420.4	4013.7
AllDay2030	325.3	674.7	29.0	2.6	13.9	469.5	848.4	1032.7	**551.9**	561.2	4509.2
ExDay2030	326.9	684.4	22.7	3.5	12.0	473.7	867.1	1033.7	516.7	562.3	4503.1
AllInt2030	327.6	687.2	21.4	2.0	10.8	477.9	861.7	1033.7	516.5	562.7	4501.3
AllIntExRes2030	327.7	688.3	22.0	1.8	10.9	478.7	859.6	1033.7	516.6	562.7	4502.1

CO_2 Emissions

From 2020 to 2030, CO_2 emissions increase with 3.6% (Table 16), reflecting the increase in demand and the changing mix of generation. Table 16 also shows the previous mentioned increase of hydropower production in *AllDay2030* compared to the other cases in 2030 leading to CO_2 emission reductions in this case.

The impact of different market designs on CO_2 emissions is very small. This is because the model for a given target year has to satisfy the same load. Also the generation from wind power and hydropower remains the same as well as the installed capacities of biomass and nuclear power with their very high capacity factors. Consequently, mainly the fossil fuelled power plants may be rescheduled depending on the market design. In total, they have to cover the same amount of load in each market design case, because all carbon free production forms are utilised nearly to maximum.

Table 16 Yearly CO2 emissions for all cases in 2020 and 2030.

	AllDay2020	ExDay2020	AllInt2020	AllIntExRes2020	AllDay2030	ExDay2030	AllInt2030	AllIntExRes2030
Total CO2 emission [MTons]	1319	1315	1315	1315	1339	1364	1366	1362
Difference relatively to ExDay [MTons]	-3.1	0.0	0.6	0.7	25.9	0.0	-1.1	2.2
Difference relative to ExDay as ratio	1.00	1.00	1.00	1.00	0.98	1.00	1.00	1.00

Operational costs of Power Generation and Market Parameters

Table 17 shows the operational costs of power generation, the value of lost load (VOLL) and the costs of not meeting spinning reserve and replacement reserve targets. The reason for the lower (system costs) of *AllDay2030* compared to the other 2030 cases is the extra production from hydropower mentioned above, and is therefore not a trustworthy result. Hydropower has only a variable operation and maintenance costs in the model, i.e. the water value is not seen as a real fuel costs and therefore excluded from the operational costs of power generation making hydropower a very cheap production form.

Table 17 Yearly operational costs of power generation (system costs) from Wilmar for 25 countries, value of lost load (VOLL), costs of not meeting spinning reserve and replacement reserve targets

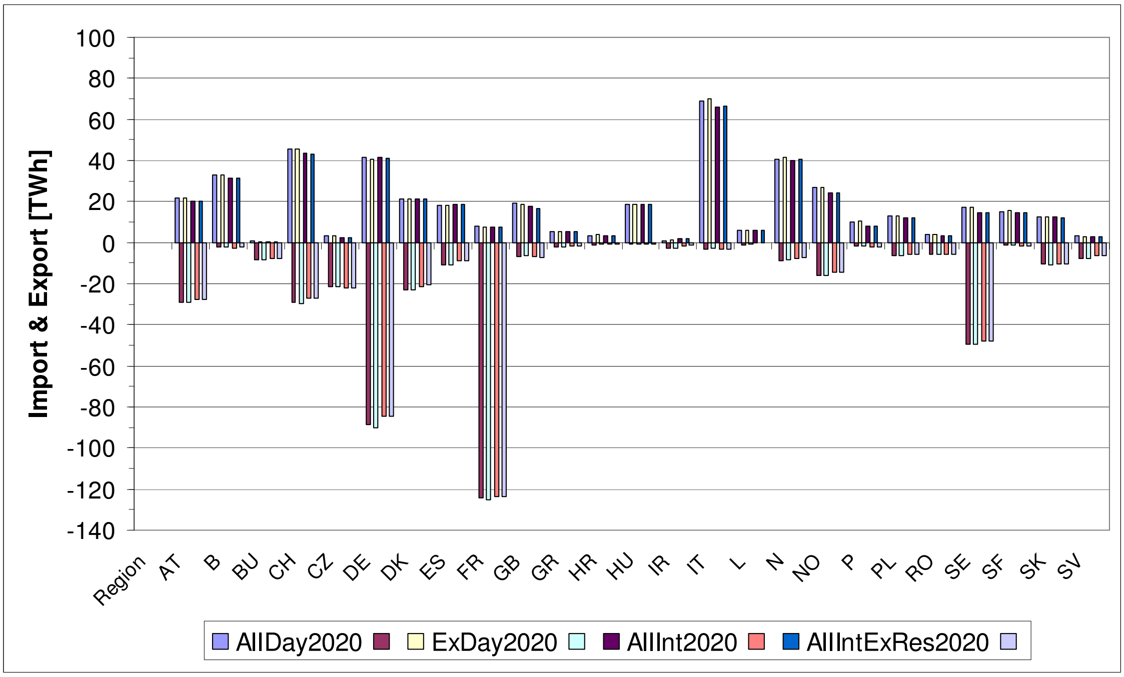
All values in MEuro	AllDay2020	ExDay2020	AllInt2020	AllIntExRes2020	AllDay2030	ExDay2030	AllInt2030	AllIntExRes2030
System costs	103302	103151	102732	102675	118163	119705	119046	118952
VOLL	4479	320	73	91	7822	807	116	171
Cost not meet replacement reserve target	74	29	5	4	101	55	16	15
Cost not meet spinning reserve target	471	24	2	2	514	42	11	10
Total	108326	103524	102812	102772	126600	120608	119188	119148
Difference relatively to ExDay	-4802	0	712	752	-5992	0	1420	1460
Relative to ExDay	1.05	1.00	0.99	0.99	1.05	1.00	0.99	0.99

The value of intraday power exchange is 1% of total operational costs being respectively 712 MEuro and 1420 MEuro for *AllInt2020* and *AllInt2030* compared to *ExDay2020* and *ExDay2030*. Only small costs savings of 40 MEuro for both 2020 and 2030 are associated with allowing exchange of replacement reserves across borders. Replacement reserves are often, although not in all countries, provided by offline fast-starting fuel oil and light oil units. These units would anyhow in many hours be offline, so the operational costs (excluding investment cost) of providing replacement reserves with these units are often zero. More detailed and, hence, realistic modelling of the costs of having these units available in the power system would increase the costs of providing replacement reserves.

Net Import and Export

Figure 17 shows yearly import and export for each country for all cases in 2020 and 2030. The influence of market design assumptions on yearly power flows is low. France is a big net exporter as well as Sweden. Net importers are Italy, Great Britain, the Netherlands, Belgium and Czech Republic. The results match well with the imports and exports calculated with Prosym as discussed above (Figure 5 and Figure 6).

a) Scenarios for 2020



b) Scenarios for 2030

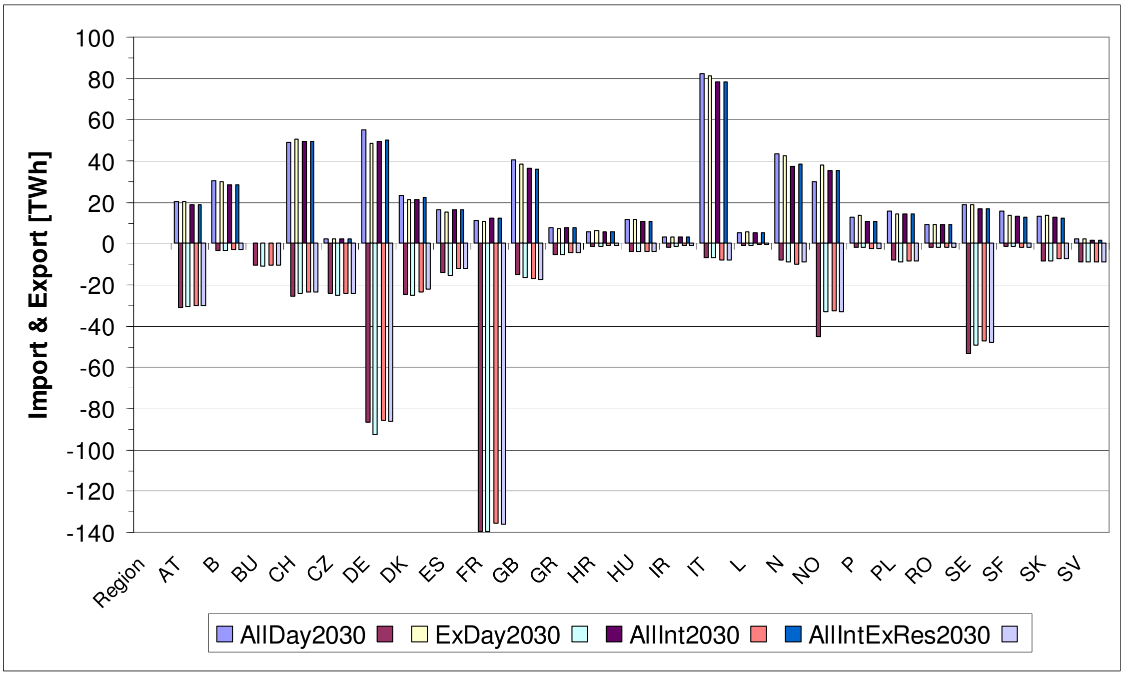


Figure 17. Yearly import (positive) and export (negative) for each country in 2020 and 2030 for all cases

6.2.2 Business-related Results

Wholesale Power Prices

Figure 18 shows that average intra-day power prices are quite similar for cases *AllInt* and *AllIntExRes* whereas fixed day-ahead scheduling of power exchange in cases *ExDay* in some countries lead to significantly higher power prices. The price peaks visible for Denmark and Slovania reflect sporadic events of lost load (accounted for at 3000 €/MWh), at periods where insufficient exchange capacity with neighbouring countries was scheduled day ahead. They illustrate another advantage of intra-day rescheduling of interconnector capacity.

Duration curves of power prices are shown for Germany for all 2030 cases in Figure 19. Power prices above 350 Euro/MWh exceed the scale of the figure. The cases *AllInt2030* and *AllIntExRes2030* have so similar power prices that their duration curves can not be distinguished from each other in the figure. Zero-prices do not occur in *AllInt2030* and *AllIntExRes2030*.

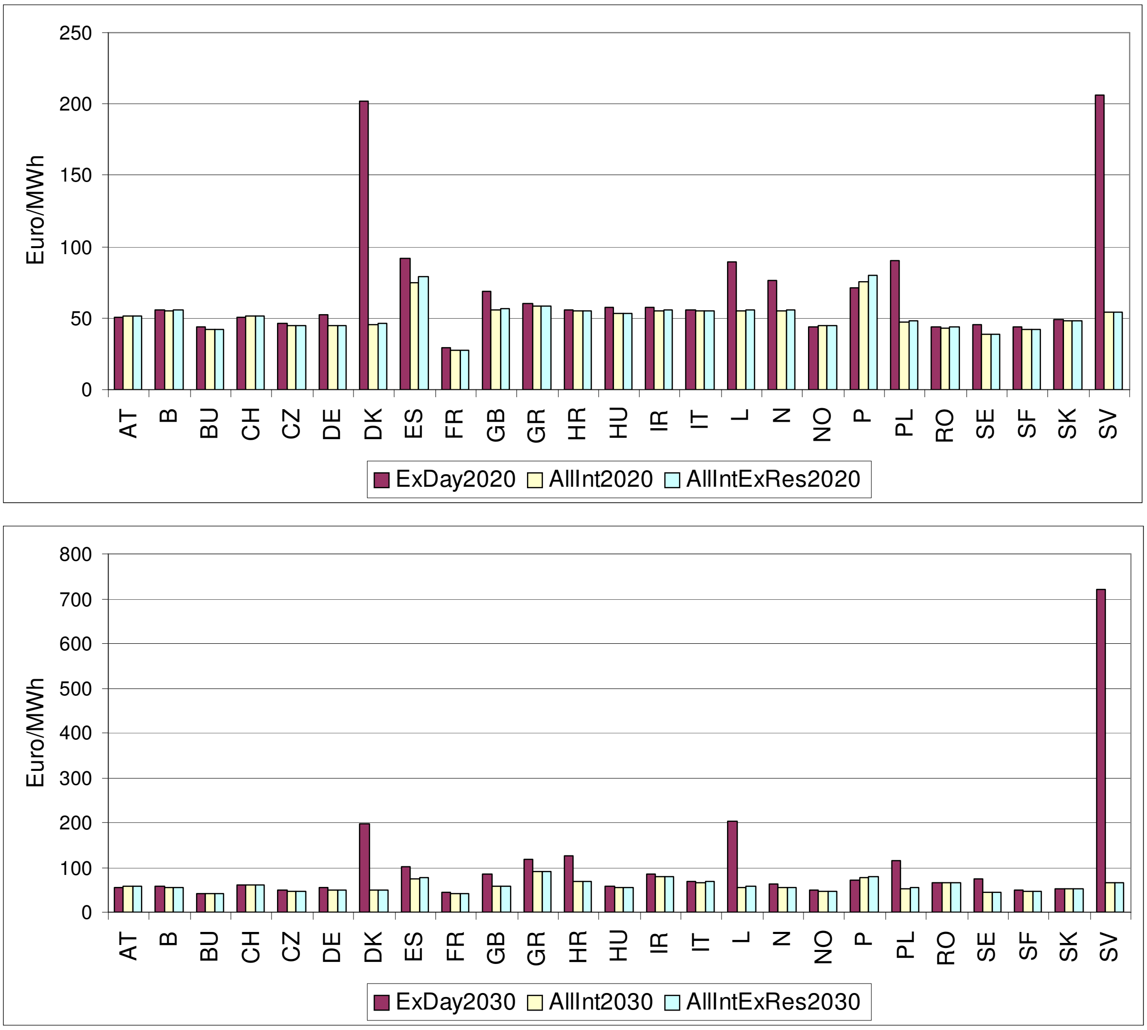


Figure 18. Yearly average intra-day power prices for each country in 2020 and 2030 for ExDay, AllInt and AllIntExRes cases

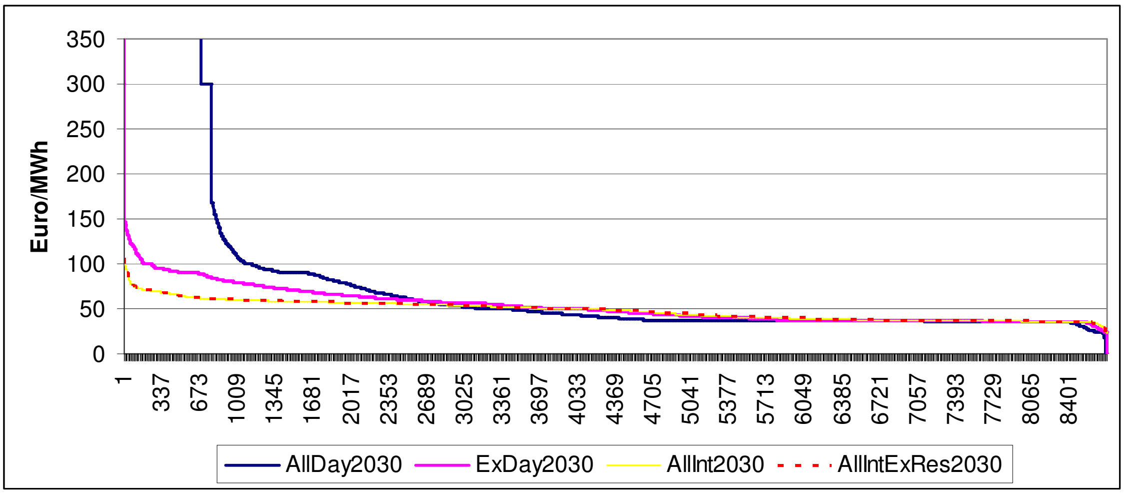
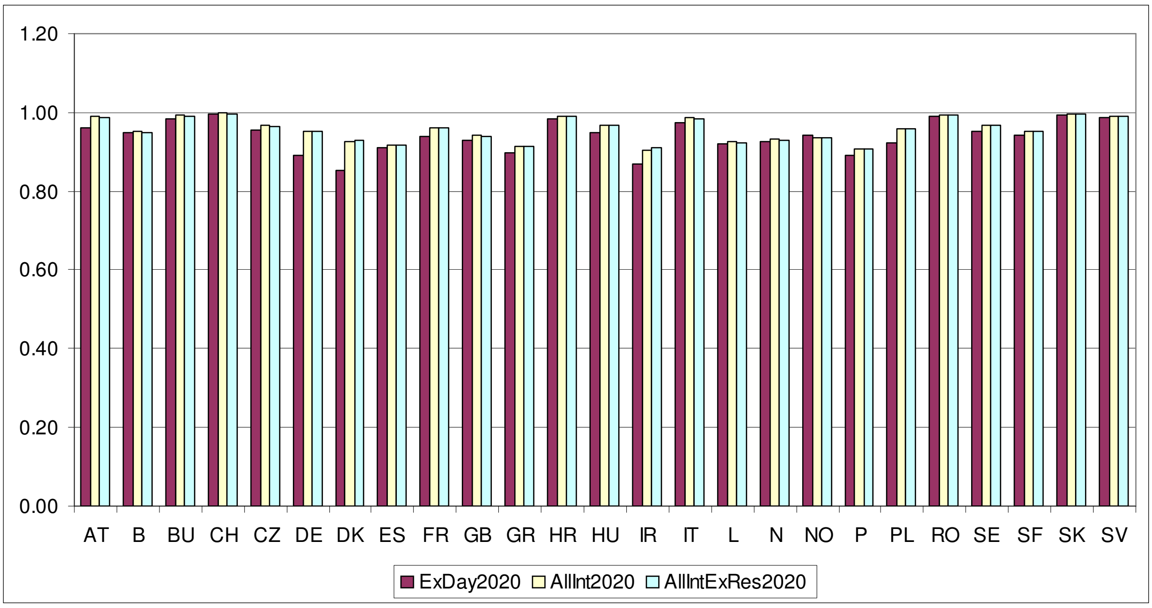


Figure 19. Duration curve of intra-day power prices in Germany for all case in 2030.

Market Value of Generation

Weighted averages prices of wind power and conventional generation have been calculated in order to asses the value of wind power in comparison to conventional generation (see Section 5.3). Figure 20 shows the ratio between average intra-day power prices weighted with respectively the wind power production and the conventional production. Prices above 300 Euro/MWh have been excluded from the average. For this reason, the unrealistic cases *AllDay* in 2020 and 2030 were excluded from the figure, as the high power prices occur frequently in these cases.

Figure 20 shows a negative correlation between intra-day power prices and wind power production, which is very pronounced in countries with a large share of wind power like Denmark, Spain, Germany or Ireland. This means, high wind power production causes a decrease in marginal costs and, assuming a perfect market, also in power prices. For most countries, intra-day rescheduling of power exchange will increase the market value of wind power as observed by the increase in the ration for most countries when going from *ExDay* to *AllInt*.



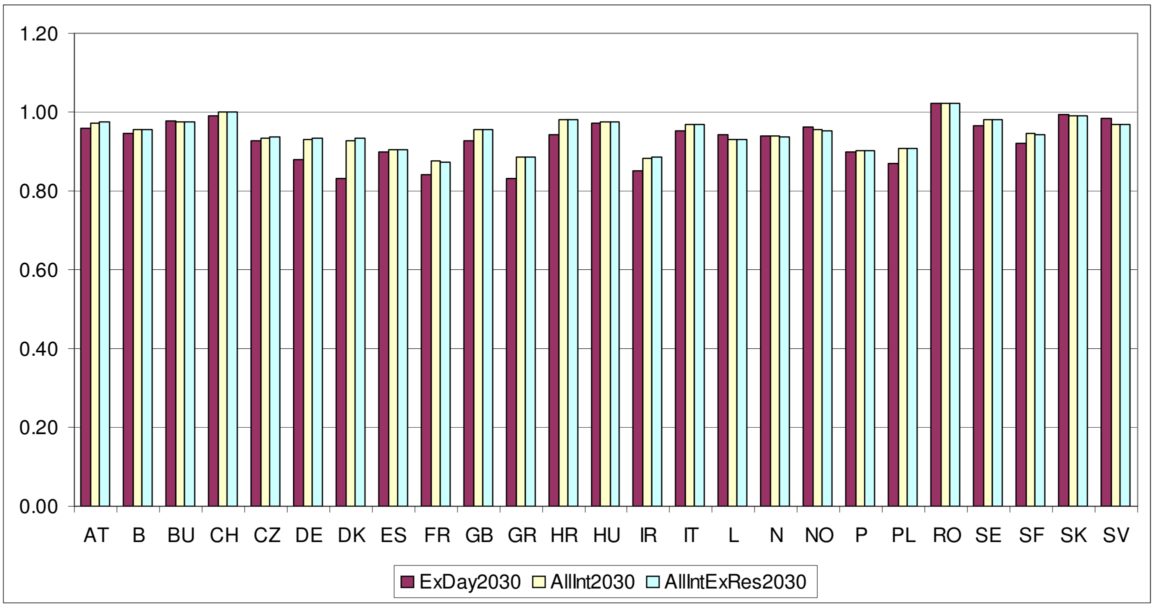


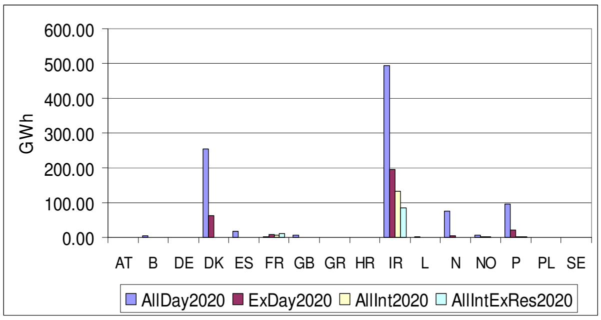
Figure 20. Ratio between the average intra-day power price weighted with respectively the wind power production and the conventional production; prices above 300 Euro/MWh have been excluded

Curtailment of Wind Power and Load

Table 18 shows that the amounts of wind curtailment and curtailed (so-called *lost*) load relatively to total wind power production and load are very small. Intra-day rescheduling of unit commitment gives a major decrease in wind curtailment and lost load as observed when comparing *AllDay* and *ExDay* in both 2020 and 2030. Intra-day power exchange further reduces wind curtailment and lost load to extremely low values, where as exchange of replacement reserves across borders decreases wind curtailment a tiny bit and increases lost load a tiny bit. Figure 21 shows that wind curtailment takes place mainly in Denmark, Ireland, Portugal, the Netherlands and Spain in 2020 and 2030. Likewise Figure 22 shows loss of load happening mostly in Spain, France, Denmark, Poland and Germany,

Table 18 Yearly wind power production, wind curtailment, load and lost load in 2020 and 2030 for all cases

	AllDay2020	ExDay2020	AllInt2020	AllIntExRes2020	AllDay2030	ExDay2030	AllInt2030	AllIntExRes2030
Wind prod [TWh]	420	420	420	420	561	562	563	563
Wind curtailment [GWh]	959	297	143	98	1623	478	108	102
Load [TWh]	3990	3990	3990	3990	4468	4468	4468	4468
Load load [GWh]	1494	107	24	30	2608	269	39	57
Wind curtailment/Total wind prod	0.0023	0.0007	0.0003	0.0002	0.0029	0.0009	0.0002	0.0002
Lost Load/Load	0.0004	0.0000	0.0000	0.0000	0.0006	0.0001	0.0000	0.0000



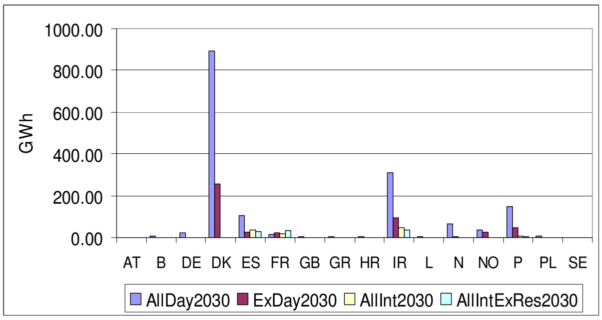
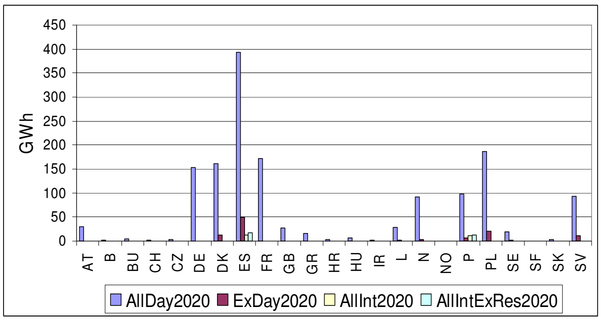


Figure 21. Yearly wind curtailment distributed on countries in 2020 (left) and 2030 (right) for all cases



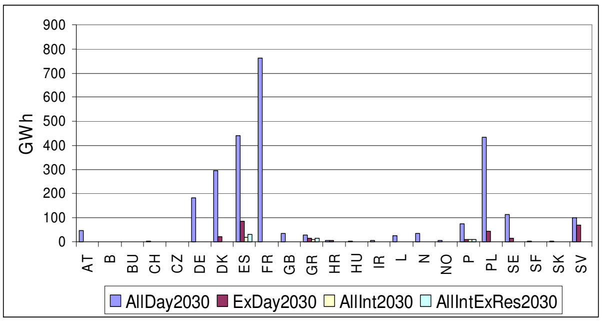


Figure 22. Yearly lost load distributed on countries in 2020 (left) and 2030 (right) for all cases

6.3 Discussion

Generation Mix

In line with the TradeWind medium wind power scenarios, the simulations comprise 206 GW of installed wind power capacity for 2020 and 280 GW for 2030. Installed conventional capacity for the 25 countries considered here is 1055 GW for 2020 and 1143 GW in 2030. The share of wind power in electricity production anticipated for 2020 and 2030 is 10.5% and 12.5%, respectively. If demand increases less than anticipated in the Eurprog scenario [Uni06], the share of renewables will be accordingly higher. In all cases, wind power will be significant all over Europe but not dominating the energy mix.

Consequently, the characteristics of conventional power plants will keep a determining influence on the overall market results like operational costs of power generation and power prices. In particular, the costs and prices of power generation will still, to a large extent, depend on fossil fuel prices and the prices of CO_2 emission allowances and the development of demand. Secondly, the operational costs and wholesale prices will significantly depend on the total fraction of wind power in a country and, with the increasing degree of market coupling, in the European internal electricity market as a whole. Thirdly, once the order of magnitude of market results is set, market rules can have a significant effect: with inflexible and small markets, volatile prices often occur. On the contrary, flexible and large markets contribute to further reducing operational costs of power generation and prices. Nevertheless, the influence of market rules is secondary, after that of the energy-economic boundary conditions. The TradeWind market modelling results for different sets of market rules need to be interpreted against this background.

Operational Costs of Power Generation

Operational costs of power generation are systematically higher with Prosym than with Wilmar. Taking into account the methodological differences in the different tools and the partly different sets of inputs, the differences are not surprising. The absolute amounts as they result from the different models should be interpreted with care. On the other hand, the tendencies and orders of magnitudes of results with both models are consistent, indicating the validity of results in terms of trends and order of magnitude.

Regarding the comparison of operational costs for different market situations the following annotations need to be made:

- The *AllDay* cases illustrate the importance of intra-day rescheduling possibilities for unit commitment as it is applied today. The cases illustrate the importance of flexible generation portfolios. However, these cases should not be considered realistic for market design. As the high penalty of 3000 €/MWh has been set arbitrarily, the quantitative results for these cases are rather indicative.
- Cross-border exchange of reserves has a minor effect on operational costs of power generation. Notably, the market models do not take into account the investment for reserve capacity. While the effect of exchanging reserves across borders on the operational costs is low, this may lead to a decrease in investment costs for reserve capacity by making existing capacity available to a neighbouring country.

Wholesale Power Prices

The calculated wholesale power prices are market clearing prices, hence, marginal prices of the marginal unit. The presented prices do not include mark-ups and the authors implicitly assume that the prices are purely cost based. No strategic bidding behaviour or use of market power has been taken into account. Finally, the model assumes transparency and equal availability of information to all market participants before the market is cleared.

Market imperfections as they have been described in other parts of the TradeWind study have not been further investigated with these models [Mor07, Woy07].

Curtailment of Wind Power and Load

Curtailment of wind power or load shedding would be necessary if no functioning procedures for intra-day rescheduling were available. In the cases with functioning intra-day markets, and even more when allowing for rescheduling of cross border trade, curtailment of wind power or load shedding occur rarely

Notably, curtailment in the applied market models only occurs as an economic decision, in order to keep must-run units online during times of low load. In practice, wind power may need to be curtailed more often and rather due to local congestion or in case of n-1 contingency. This reason for curtailment could not be studied with the models.

7 SUMMARY AND CONCLUSIONS

Approach

The functioning of European electricity markets with high share of installed wind power capacity has been analyzed, allowing for an evaluation of market efficiency for different market designs and stages of integration. Market results have been calculated with two different simulation models namely with Prosym and with the Wilmar Planning Tool. Different scenarios have been examined with the different tools. This allowed covering a wide range of different parameter combinations while choosing the different scenarios in line with the specific features of the different modelling tools.

The market efficiency (as characterized by selected indicators) has been assessed for a set of market rule parameters, affecting the market functioning in terms of

- the available interconnector capacity (constraints),
- the flexibility of rescheduling of dispatch decisions (time dimension) and
- the flexibility of the cross-border exchange (time + spatial dimension).

These parameters must be studied in a constant energy-economic context, defined by the electricity demand, the generation mix including the overall wind power share and the prices of fossil fuel and CO_2 emission allowances. The impact of changes in the energy economic context has been studied by varying some of the characteristics that determine the context.

Calculations for the different cases return socio-economic quantities like the operational costs of power generation, that reflect the value of different cases for society, and business-related quantities that reflect the potential value from the viewpoint of a market participant.

Models and Scenarios

Wind power scenarios, electricity demand, fuel prices and CO_2 costs and transmission capacity values between countries are the same for the two modelling tools. The assumptions are partly different regarding the level of detail with which the generation portfolio is modelled, but also regarding the treatment of reserves and possibilities for rescheduling. The calculations with Prosym cover 18 European countries, those with Wilmar 25 countries. The results from both tools are quantified by means of a consistent set of indicators.

The calculations range throughout a space of market rule combinations. For Wilmar, the different cases range from nationally contained spot markets with low flexibility for rescheduling to an integrated European market with possibilities for transferring even reserve power over borders. Four scenarios have been investigated for each of the scenario years 2020 and 2030. For Prosym the calculations cover four cases for the target year 2020, characterized by different degrees of connectivity between countries and by differences in gate closure from day-ahead to intra-day. The gate-closure is reflected by assumptions on the wind power forecast error and the associated requirements for spinning reserves. In addition, the sensitivities have been checked with Prosym for the following three parameters: namely, installed wind power capacity, oil and gas prices, and wind power curtailment strategy.

Energy-economic Context

The operational costs of power generation are calculated as the sum of fuel costs including start-up fuel consumption, start-up costs, costs of consuming CO_2 emission allowances, and operation and maintenance costs. Energy not served and reserve deficiencies are not included but reported separately. Fuel prices and prices of CO_2 mission allowances, electricity demand and the share of wind power in the system have a direct effect on the operational costs.

According to the market simulations carried out with the tools Wilmar and Prosym, the main effects of the energy economic context are as follows:

- Wind power as a fuel-free source of power contributes significantly to reducing the operational costs (excluding investments and maintenance) of power generation: Assuming the same wind power penetration as of 2008, the operational cost of power generation in 2020 for the 18 countries modelled with Prosym would be 119.2 billion €. An additional 128 GW of wind power to be installed between 2008 and 2020 yields a reduction of almost 10% or 10.8 billion € per year in 2020. The macro-economic cost savings of wind power replacing conventional sources are then 42 €/MWh. This estimate does not take account of investments nor of specific additional costs related to wind power integration such as additional balancing cost and additional incentive costs. Therefore, these savings may be interpreted as being the admissible surplus cost of wind power generation when replacing conventional generation. In other words, from the public support that wind energy receives via quota systems or feed-in tariffs, 42 €/MWh is returned to the public via the consecutive reduction in operational costs of generation. Along with this cost reduction, wind power also contributes to a significant reduction of wholesale power prices in the different countries. The actual reduction in average power price due to wind depends strongly on the country.

- Although wind power capacity between 2020 and 2030 was assumed to increase by 70 GW, CO_2 emissions increase with 3.6%. This increase in CO_2 is mainly due to the structure of the power generation mix and the increasing electricity demand in the cases modelled. Notably, the applied increase in electricity demand according to Europrog (see Appendix 1) is relatively high in comparison to other data sources for the years beyond 2020. In particular, Europrog considers only little improvements in energy efficiency on the long term. These results emphasize the importance of energy efficiency and high CO_2 prices in reducing CO_2 emissions.

- With doubled oil and gas prices in 2020 as compared to the European Commission's 2007 baseline scenario (46 $05/boe), the operational costs of power generation will be about 23% or €25 billion higher. In most countries, 2020 power prices would increase by €20-30/MWh if the fuel prices doubled. Accordingly, the macro-economic value of fuel-free generation in this case would be higher.

Interconnector Capacity

As not much additional cross-border capacity is considered in the best NTC case compared to the base NTC case (Appendix 2) and since this is only done for a few countries, there are no significant changes in the import-export balance of most countries. France and Germany will remain net exporters while Italy will remain net importers of electricity. A significant increase of power exchange can be observed for those countries that today are connected only to a limited extent and for which large increases in interconnection capacity have been assessed in Chapter 5. The difference is especially significant with regard to imports into Italy and into Great Britain.

In conclusion, simulation results show savings with increasing NTC. It is recommended to further investigate the effect of major transmission upgrades as suggested in WP5 in follow-up studies.

Flexibility of Re-scheduling of Dispatch Decisions

The following conclusions can be made regarding the organisation of cross-border exchange, unit commitment and scheduling in international electricity markets:

- In general terms, allowing unit commitment to be re-scheduled as close as possible to real time leads to savings in operational costs of power generation and stable power prices. Not allowing intra-day rescheduling would cause volatile and regularly spiking prices, especially in smaller countries.

- Reducing the demand for reserves by accepting wind power forecasts up to three hours before delivery would yield a reduction in operational costs of power generation of €260 million per year. This cost reduction assumes a perfect market and would be much larger under current market conditions.

The impact of different market designs on CO_2 emissions is very small, namely 0.1 up to 0.3% of emissions as calculated for the ExDay case for each target year. This is because the model, for a given target year, has to satisfy the same load. Moreover, the generation from wind power and hydropower remains the same, as do the installed capacities of biomass and nuclear power with their very high capacity factors. In total, they have to cover the same amount of load in each market design case because all carbon free production forms are utilised nearly to the maximum amount. Consequently, overall CO_2 emissions mainly depend on whether the merit order gives priority to coal or gas fired units.

Flexibility of the Cross-border Exchange

The advantage of flexible markets becomes much more prominent when flexible unit commitment and rescheduling are not only applicable to national markets but also to cross-border exchange.

- Allowing for intra-day rescheduling of cross border exchange will lead to savings in operational costs of power generation of approximately 1%, or in the order of €1-2 billion per year compared to day-ahead cross-border exchange.

- The cross-border exchange of reserves has a positive but relatively low effect on the operational costs of power generation. In an unbundled market, deviations from the programme are balanced first of all from the portfolios of the parties responsible for balancing. Only afterwards they put demand on the reserve power markets. Nevertheless, cross-border exchange of reserves may lead to a decrease in investment costs for reserve capacity by making existing capacity available across borders.

In conclusion, the establishment of intra-day markets for cross-border trade is key for market efficiency in Europe. In order to ensure efficient allocation of the interconnectors, they should be allocated directly to the market via implicit auction.

For the assumed development of demand and generation mix, wind power curtailment and load shedding hardly ever occur when the market is well designed. An international exchange of reserves is not the first priority for a good market design. It is better to keep the need for reserve power low by intra-day rescheduling of power exchange and by intra-day rescheduling of unit commitment and dispatch of units. The main benefit of exchanging reserve power could consist of possible savings from investments in flexible power plants due to reserves being shared across borders.

Overall Conclusion

In short, the operational costs of power generation in 2020 to 2030 with a large share of wind power will be sensitive to:

- fuel prices,

- the amount of energy generated from wind.

Requirements for a good market design in Europe are:

- features for intra-day rescheduling of generators and trade on an international level for low operational costs of power generation and stable prices,

- wide-spread application of implicit auctioning to allocate cross-border capacity

- to facilitate intra-day wind power forecasting in order to decrease reserve requirements,

- the availability of sufficient interconnection capacity to enable prices to converge.

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9 APPENDIX

APPENDIX 1

Table 19: Annual electricity consumption for power flow and market modelling in TWh; scenario based on Eurprog 2006 [Uni06]

[TWh]	2005	2008	2010	2015	2020	2030
DE	556	566	572	573	575	572
NL	115	122	129	143	157	191
BE	88	93	97	103	109	109
LU	6	7	6	7	7	7
FR	482	493	508	530	552	618
CH	63	64	65	72	80	98
IT	330	352	366	408	450	550
AT	63	65	63	66	70	83
ES	253	288	317	353	390	463
NO	122	128	133	138	143	153
SE	145	148	150	152	154	156
CZ	63	66	68	73	77	83
SI	13	15	16	17	18	20
GR	53	60	67	75	84	101
HU	39	43	45	49	53	58
GB	377	417	458	485	512	523
PT	50	55	59	67	76	97
HR	17	18	19	21	23	28
RS	42	45	48	53	58	58
RO	52	56	59	69	78	105
BG	36	36	36	44	51	62
BA	11	12	12	14	15	18
SK	26	29	31	33	35	39
PL	131	136	136	148	160	181
SF	85	93	96	101	107	117
DK	36	37	38	40	41	45
MK	8	8	8	8	8	8
IE	26	30	34	38	43	43
Total	3288	3482	3636	3880	4126	4586

APPENDIX 2

Net transfer capacity (NTC) data and high-voltage DC (HVDC) interconnector capacities between countries for different cases.

2020 NTC Base Case

Country A NTC Data [MW]	Country B	Short A	Short B	NTC A2B	NTC B2A
Norway North	Norway Middle	NO3	NO2	600	600
Norway North	Sweden North	NO3	SE3	600	700
Norway Middle	Sweden North	NO2	SE3	1560	1300
Norway Middle	Norway South	NO2	NO1	300	300
Norway South	Sweden Middle	NO1	SE2	2050	1850
Sweden North	Finland North	SE3	SF2	1600	1200
Sweden North	Sweden Middle	SE3	SE2	7000	7000
Sweden South	Sweden Middle	SE1	SE2	4000	4000
Sweden South	Denmark-E	SE1	DKE	1350	1750
Austria	Slovenia	AT	SV	350	650
Austria	Italy	AT	IT	3014	1164
Austria	Germany	AT	DE	1800	2000
Austria	Switzerland	AT	CH	1200	1200
Austria	Hungary	AT	HU	856	171
Belgium	France	B	FR	2379	3460
Belgium	The Netherlands	B	N	2400	2400
Bosnia-Herzegovina	Croatia	BH	HR	600	600
Bosnia-Herzegovina	Serbia & Montenegro	BH	SC	695	540
Switzerland	Italy	CH	IT	3890	1460
Switzerland	Germany	CH	DE	4000	2100
Switzerland	France	CH	FR	2300	3200
Croatia	Slovenia	HR	SV	900	900
Czech Republic	Germany	CZ	DE	2300	700
Czech Republic	Poland	CZ	PL	800	1660
Czech Republic	Slovak Republic	CZ	SK	1300	900
Czech Republic	Austria	CZ	AT	430	1032
Germany	France	DE	FR	2750	2850
Germany	Poland	DE	PL	1200	1100
Spain	France	ES	FR	791	2216
Spain	Portugal	ES	P	3139	2898
France	Italy	FR	IT	2650	995
Greece	Bulgaria	GR	BU	500	500
Greece	Macedonia	GR	MC	705	101
Italy	Slovenia	IT	SV	418	1123
The Netherlands	Germany	N	DE	3000	3850
Romania	Hungary	RO	HU	700	600
Romania	Bulgaria	RO	BU	750	750
Romania	Serbia & Montenegro	RO	SC	1483	1711
Serbia & Montenegro	Macedonia	SC	MC	0	0
Serbia & Montenegro	Croatia	SC	HR	540	500
Serbia & Montenegro	Bulgaria	SC	BU	500	650
Serbia & Montenegro	Hungary	SC	HU	1000	800
Slovak Republic	Hungary	SK	HU	1300	800
Slovak Republic	Poland	SK	PL	550	550
Ukraine	Slovak Republic	UA	SK	450	450
Ukraine	Hungary	UA	HU	800	0
Ukraine	Romania	UA	RO	500	200

Denmark-W	Germany	DKW	D2	2770	1755

HVDC Interconnector Capacity [MW]

Sweden	Finland	SE	SF	1350	1350
Denmark-West	Norway South	DKW	NO1	1450	1450
Denmark-West	Sweden-South	DKW	SE2	485	485
Germany	Denmark-E	D1	DKE	550	550
France	Great Britain	FR	GB	2000	2000
Italy	Greece	IT	GR	500	500
Sweden South	Poland	SE1	PL	600	600
Sweden South	Germany	SE1	D2	600	600
Scotland (GB North)	Northern Ireland	GBN	NI	500	500
Denmark-West	Denmark-East	DKW	DKE	600	600
The Netherlands	Norway South	NL	NO1	700	700
The Netherlands	Great Britain	NL	GB	1000	1000
Wales (GB South)	Ireland (Republic)	GBS	ROI	500	500

2020/2030 NTC Best Case (High)

Country A **NTC Data [MW]**	**Country B**	**Short A**	**Short B**	**NTC A2B**	**NTC B2A**
Norway North	Norway Middle	NO3	NO2	600	600
Norway North	Sweden North	NO3	SE3	600	700
Norway Middle	Sweden North	NO2	SE3	1560	1300
Norway Middle	Norway South	NO2	NO1	300	300
Norway South	Sweden Middle	NO1	SE2	2050	1850
Sweden North	Finland North	SE3	SF2	1600	1200
Sweden North	Sweden Middle	SE3	SE2	7000	7000
Sweden South	Sweden Middle	SE1	SE2	4000	4000
Sweden South	Denmark-E	SE1	DKE	1350	1750
Austria	Slovenia	AT	SV	350	650
Austria	Italy	AT	IT	3014	1164
Austria	Germany	AT	DE	1800	2000
Austria	Switzerland	AT	CH	1200	1200
Austria	Hungary	AT	HU	856	171
Belgium	France	B	FR	2379	3460
Belgium	The Netherlands	B	N	2400	2400
Bosnia-Herzegovina	Croatia	BH	HR	600	600
Bosnia-Herzegovina	Serbia & Montenegro	BH	SC	695	540
Switzerland	Italy	CH	IT	3890	1460
Switzerland	Germany	CH	DE	4000	2100
Switzerland	France	CH	FR	2300	3200
Croatia	Slovenia	HR	SV	900	900
Czech Republic	Germany	CZ	DE	2300	700
Czech Republic	Poland	CZ	PL	800	1660
Czech Republic	Slovak Republic	CZ	SK	1300	900
Czech Republic	Austria	CZ	AT	430	1032
Germany	France	DE	FR	2750	2850
Germany	Poland	DE	PL	1200	1100
Spain	France	ES	FR	791	2216
Spain	Portugal	ES	P	3139	2898
France	Italy	FR	IT	2650	995
Greece	Bulgaria	GR	BU	500	500

Greece	Macedonia	GR	MC	705	101
Italy	Slovenia	IT	SV	418	1123
The Netherlands	Germany	N	DE	3000	3850
Romania	Hungary	RO	HU	700	600
Romania	Bulgaria	RO	BU	750	750
Romania	Serbia & Montenegro	RO	SC	1483	1711
Serbia & Montenegro	Macedonia	SC	MC	0	0
Serbia & Montenegro	Croatia	SC	HR	540	500
Serbia & Montenegro	Bulgaria	SC	BU	500	650
Serbia & Montenegro	Hungary	SC	HU	1000	800
Slovak Republic	Hungary	SK	HU	1300	800
Slovak Republic	Poland	SK	PL	550	550
Ukraine	Slovak Republic	UA	SK	450	450
Ukraine	Hungary	UA	HU	800	0
Ukraine	Romania	UA	RO	500	200
Denmark-W	Germany	DKW	D2	2770	1755

HVDC Interconnector Capacity [MW]

Sweden	Finland	SE	SF	1350	1350
Denmark-West	Norway South	DKW	NO1	2050	2050
Denmark-West	Sweden-South	DKW	SE2	845	845
Germany	Denmark-E	D1	DKE	1100	1100
France	Great Britain	FR	GB	4000	4000
Italy	Greece	IT	GR	1500	1500
Sweden South	Poland	SE1	PL	1200	1200
Sweden South	Germany	SE1	D2	1200	1200
Scotland (GB North)	Northern Ireland	GBN	NI	500	500
Denmark-West	Denmark-East	DKW	DKE	1200	1200
The Netherlands	Norway South	NL	NO1	1400	1400
The Netherlands	Great Britain	NL	GB	1000	1000
Wales (GB South)	Ireland (Republic)	GBS	ROI	500	500
Germany	Norway South	D1	NO1	1400	1400
Norway South	Norway Middel	NO1	NO2	1000	1000
France	Italy	FR	IT	1000	1000
Italy	Croatia	IT	HR	1000	1000
Scotland (GB North)	Norway South	GBN	NO1	2000	2000

APPENDIX 3

Prosym results: statistical properties of the market clearing price and duration curves of the market clearing price for selected countries

Market Prices: Comparison for Selected Countries

Table 20. Differences in statistical properties of the market clearing prices for different cases; calculation with Prosym for 18 countries

	Differences in price indices:		Differences in price indices of Clearing price in a perfect market in €/MWh (Calculations based on hourly Prosym Output)																
Scenarios 2020		Price indices:	**AT**	**BE**	**CH**	**CZ**	**DE**	**DKE**	**DKW**	**ES**	**FR**	**GB**	**HU**	**IT**	**NL**	**PL**	**PT**	**SI**	**SK**
Sc.1 min Sc.2	[baseNTC (D-1)] min [baseNTC (T-3)]	mean value	-0.29	-0.66	-0.40	-0.09	-0.14	-0.13	-0.14	-0.11	-0.64	-0.77	-0.12	-0.25	-0.27	-0.12	-0.08	-0.19	-0.11
Sc.3 min Sc.4	[highNTC (D-1)] min [highNTC: (T-3)]	mean value	-0.29	-0.35	-0.18	-0.08	-0.14	-0.14	-0.14	-0.08	-0.41	-0.49	-0.10	-0.27	-0.19	-0.13	-0.07	-0.22	-0.10
Sc.1 min Sc.3	[baseNTC (D-1)] min [highNTC: (D-1)]	mean value	0.28	0.51	0.47	-0.06	-0.13	1.16	-0.19	-0.05	-1.15	4.10	-0.03	0.39	0.71	-0.04	-0.01	0.47	0.01
Sc.2 min Sc.4	[baseNTC (T-3)] min [highNTC: (T-3)]	mean value	0.27	0.82	0.69	-0.04	-0.12	1.15	-0.20	-0.01	-0.92	4.38	-0.01	0.37	0.79	-0.06	0.01	0.43	0.02
Sc.1 min Sc.5	[baseNTC (D-1) wind2020] min [baseNTC (D-1) wind2008]	mean value	-2.14	-12.57	-7.97	-1.92	-2.36	-3.30	-2.92	-13.72	-12.86	-16.18	-0.58	-1.24	-4.99	-1.92	-14.71	-1.30	-0.65
Sc.1 min Sc.6	[baseNTC ...] min [baseNTC oil and gas price * 200%]	mean value	-22.30	-27.30	-20.81	-4.26	-4.85	-8.48	-7.25	-25.29	-14.27	-20.71	-26.33	-25.97	-28.94	-5.32	-25.00	-25.37	-26.35
Sc.1 min Sc.7	[baseNTC...] min [baseNTC wind as must run]	mean value	0.00	-0.01	0.03	0.00	0.00	0.03	0.00	0.00	0.00	-0.01	-0.01	0.01	0.00	0.00	0.00	0.02	-0.01
	Differences in price indices:		Differences in price indices of Clearing price in a perfect market in €/MWh (Calculations based on hourly Prosym Output)																
Scenarios 2020		Price indices:	**AT**	**BE**	**CH**	**CZ**	**DE**	**DKE**	**DKW**	**ES**	**FR**	**GB**	**HU**	**IT**	**NL**	**PL**	**PT**	**SI**	**SK**
Sc.1 min Sc.2	[baseNTC (D-1)] min [baseNTC (T-3)]	stddev	-0.31	-0.45	-0.20	-0.25	-0.33	-0.07	-0.11	-0.01	-0.87	0.05	-0.13	-0.11	0.10	-0.21	0.03	0.28	-0.08
Sc.3 min Sc.4	[highNTC (D-1)] min [highNTC: (T-3)]	stddev	-0.53	-0.02	0.34	-0.20	-0.36	-0.13	-0.12	0.07	-0.08	0.01	0.14	-0.11	-0.03	-0.35	0.07	0.13	0.17
Sc.1 min Sc.3	[baseNTC (D-1)] min [highNTC: (D-1)]	stddev	1.45	0.67	1.23	0.27	0.09	7.16	-0.43	-0.08	1.91	5.00	-0.36	1.31	2.79	0.04	-0.05	1.63	0.07
Sc.2 min Sc.4	[baseNTC (T-3)] min [highNTC: (T-3)]	stddev	1.23	1.10	1.77	0.32	0.06	7.10	-0.44	0.00	2.70	4.96	-0.09	1.30	2.65	-0.10	0.00	1.48	0.32
Sc.1 min Sc.5	[baseNTC (D-1) wind2020] min [baseNTC (D-1) wind2008]	stddev	-7.41	-12.70	-13.36	-0.22	-0.33	-6.06	-4.25	-14.00	-18.50	-12.12	-1.66	-5.81	-8.32	-0.20	-14.51	-5.35	-1.84
Sc.1 min Sc.6	[baseNTC ...] min [baseNTC oil and gas price * 200%]	stddev	-8.91	5.36	-0.95	-10.20	-10.80	-9.72	-7.88	7.23	-6.47	5.33	-6.87	-6.00	-4.36	-10.73	7.44	-4.94	-7.06
Sc.1 min Sc.7	[baseNTC...] min [baseNTC wind as must run]	stddev	-0.18	-0.04	0.00	-0.01	-0.01	0.16	0.00	0.00	0.01	0.01	0.01	0.01	0.00	-0.01	0.00	0.02	0.01
	Differences in price indices:		Differences in price indices of Clearing price in a perfect market in €/MWh (Calculations based on hourly Prosym Output)																
Scenarios 2020		Price indices:	**AT**	**BE**	**CH**	**CZ**	**DE**	**DKE**	**DKW**	**ES**	**FR**	**GB**	**HU**	**IT**	**NL**	**PL**	**PT**	**SI**	**SK**
Sc.1 min Sc.2	[baseNTC (D-1)] min [baseNTC (T-3)]	min	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sc.3 min Sc.4	[highNTC (D-1)] min [highNTC: (T-3)]	min	-12.33	-12.32	-12.32	-12.32	-12.33	-12.32	-12.33	0.00	-12.32	-12.32	-12.32	-12.32	-12.32	-12.32	0.00	-12.32	-12.32
Sc.1 min Sc.3	[baseNTC (D-1)] min [highNTC: (D-1)]	min	12.33	12.33	12.32	12.32	12.33	12.32	12.33	0.00	12.32	12.33	12.33	12.32	12.32	12.32	0.00	12.32	12.32
Sc.2 min Sc.4	[baseNTC (T-3)] min [highNTC: (T-3)]	min	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Sc.1 min Sc.5	[baseNTC (D-1) wind2020] min [baseNTC (D-1) wind2008]	min	-3.49	-3.48	-3.49	-3.49	-3.49	-3.49	-3.49	-13.90	-2.72	-2.90	-3.49	-3.50	-3.49	-3.49	-29.76	-3.49	-3.50
Sc.1 min Sc.6	[baseNTC ...] min [baseNTC oil and gas price * 200%]	min	-2.91	-3.48	-2.91	-2.90	-2.91	-2.91	-2.91	0.00	-2.72	-2.72	-2.90	-3.49	-3.49	-2.91	0.00	-3.49	-2.91
Sc.1 min Sc.7	[baseNTC...] min [baseNTC wind as must run]	min	-2.91	-3.48	-2.91	-2.91	-2.91	-2.91	-2.91	1.20	-2.72	-2.72	-2.90	-2.91	-3.49	-2.91	1.20	-2.91	-2.91
	Differences in price indices:		Differences in price indices of Clearing price in a perfect market in €/MWh (Calculations based on hourly Prosym Output)																
Scenarios 2020		Price indices:	**AT**	**BE**	**CH**	**CZ**	**DE**	**DKE**	**DKW**	**ES**	**FR**	**GB**	**HU**	**IT**	**NL**	**PL**	**PT**	**SI**	**SK**
Sc.1 min Sc.2	[baseNTC (D-1)] min [baseNTC (T-3)]	max	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00
Sc.3 min Sc.4	[highNTC (D-1)] min [highNTC: (T-3)]	max	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sc.1 min Sc.3	[baseNTC (D-1)] min [highNTC: (D-1)]	max	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00
Sc.2 min Sc.4	[baseNTC (T-3)] min [highNTC: (T-3)]	max	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sc.1 min Sc.5	[baseNTC (D-1) wind2020] min [baseNTC (D-1) wind2008]	max	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sc.1 min Sc.6	[baseNTC ...] min [baseNTC oil and gas price * 200%]	max	0.00	0.00	0.00	-82.51	-64.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-64.85	0.00	0.00	0.00
Sc.1 min Sc.7	[baseNTC...] min [baseNTC wind as must run]	max	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Belgium

For Belgium the differences between the market clearing price in scenario *base case NTC, T-3* and market clearing price in scenario *base case NTC, D-1* is for hours when marginal costs met a sharp drop (Figure 23). The difference of the average clearing price is 0.66 €/MWh.

If the NTC values increase from *base case NTC* to *best case (high) NTC* (see Appendix 1), the differences between t-3 and D-1 scenarios are reduced as constraints decrease (Figure 24). The difference of the average clearing price is 0.35 €/MWh.

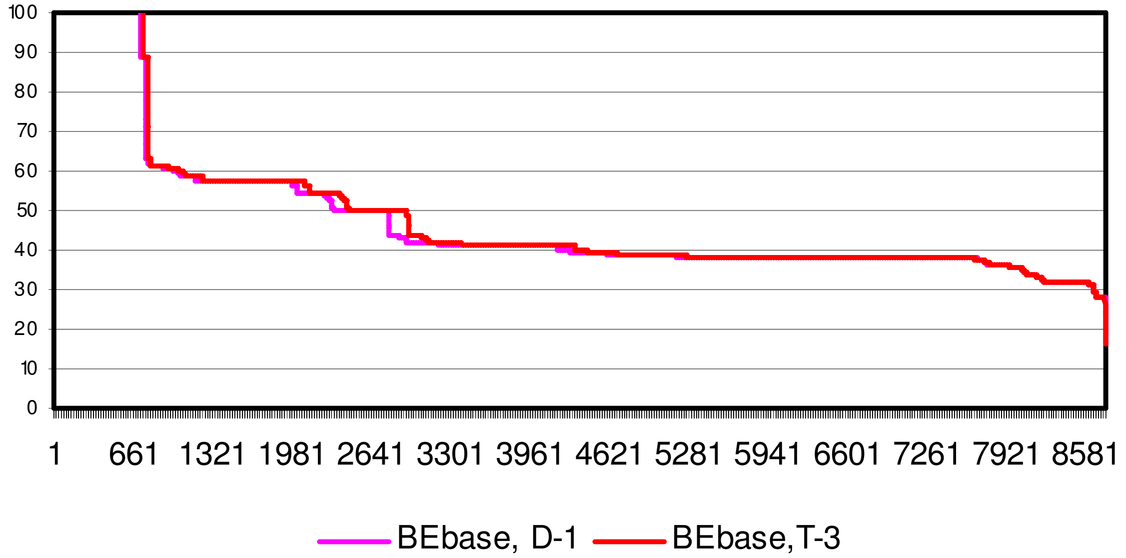

Figure 23. Duration curves of the market clearing prices in Belgium for gate closure day-ahead and intra-day (year 2020, base case NTC, medium wind power)

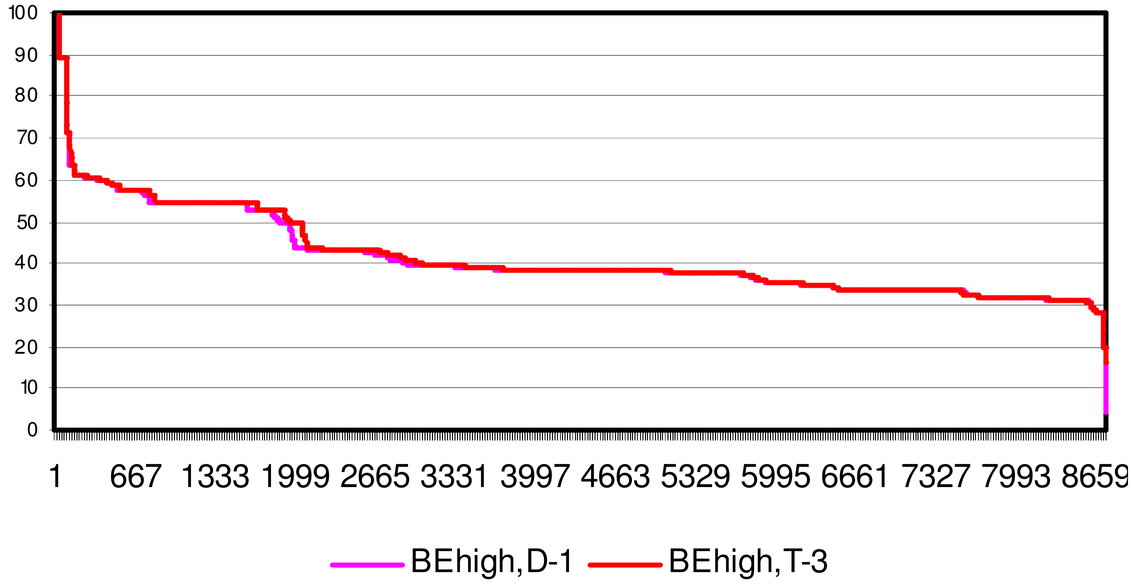

Figure 24. Duration curves of the market clearing prices in Belgium for gate closure day-ahead and intra-day (year 2020, best case (high) NTC, medium wind power)

Germany

For Germany the differences between the market clearing price in the *base case NTC, t-3* scenario and in the base NTC, D-1 scenario are very slight. The difference of the average clearing price is 0.14 €/MWh for both *base case NTC* and *best case (high) NTC* (Figure 25 *and* Figure 26).

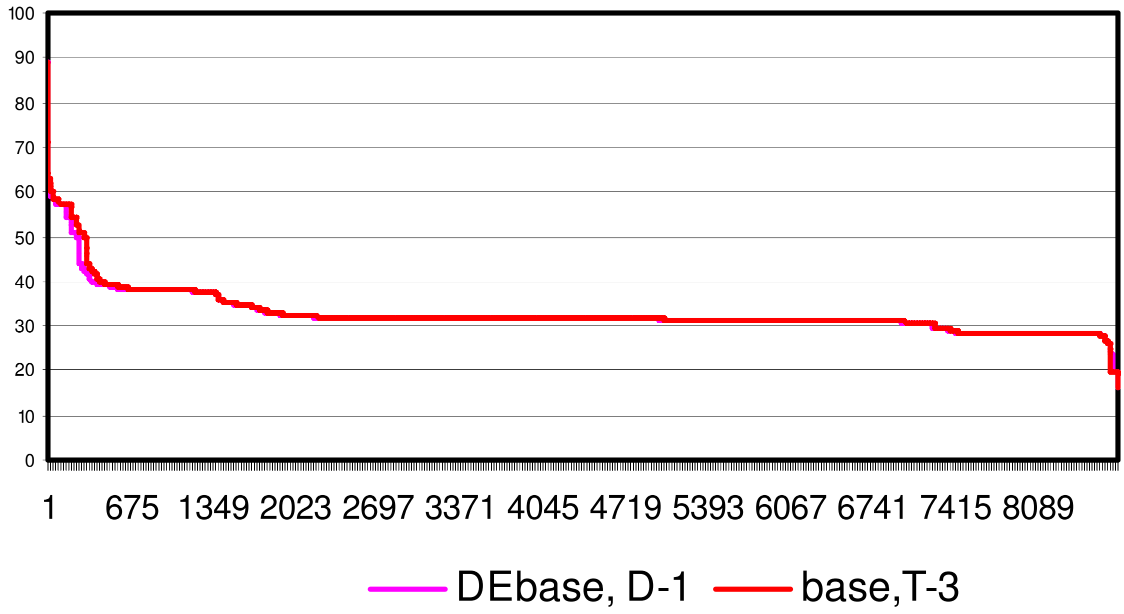

Figure 25. Duration curves of the market clearing prices in Germany for gate closure day-ahead and intra-day (year 2020, base case NTC, medium wind power)

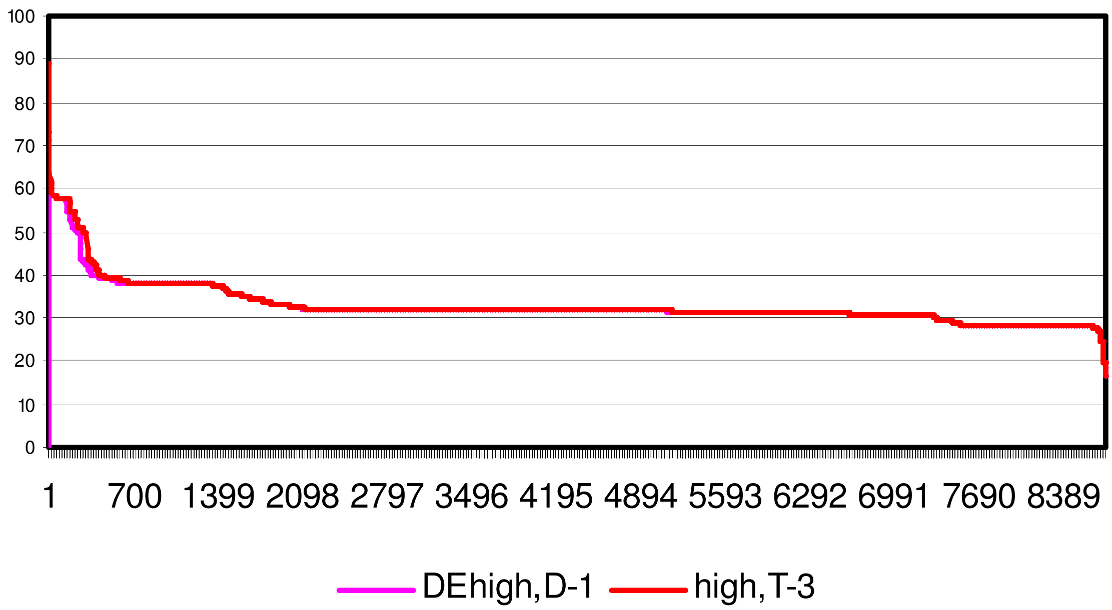

Figure 26. Duration curves of the market clearing prices in Germany for gate closure day-ahead and intra-day (year 2020, best case (high) NTC, medium wind power)

Spain

For Spain, virtually no difference is visible between the market clearing price in scenario *base case NTC, t-3* and market clearing price in scenario *base case NTC, D-1* (Figure 27 and Figure 28). The difference of the average clearing price is 0.11 €/MWh.

If the NTC values increase from *base case NTC* to *best case (high) NTC* (see Appendix 1), the differences between market clearing price in scenario *base case NTC, T-3* and market clearing price in scenario *base case NTC, D-1* become even lower, namely, 0.07 €/MWh difference of the average clearing price.

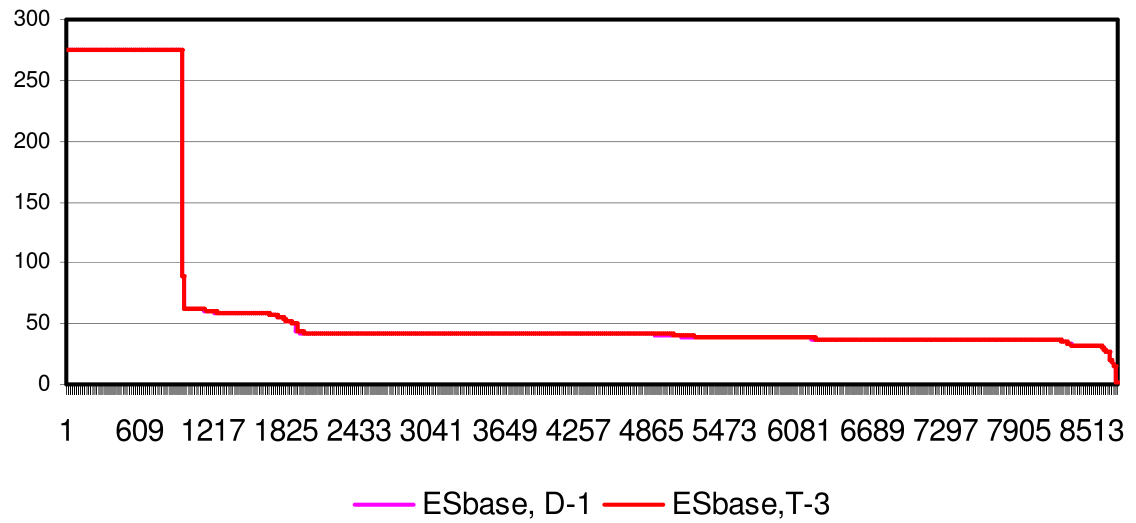

Figure 27. Duration curves of the market clearing prices in Spain for gate closure day-ahead and intra-day (year 2020, base case NTC, medium wind power)

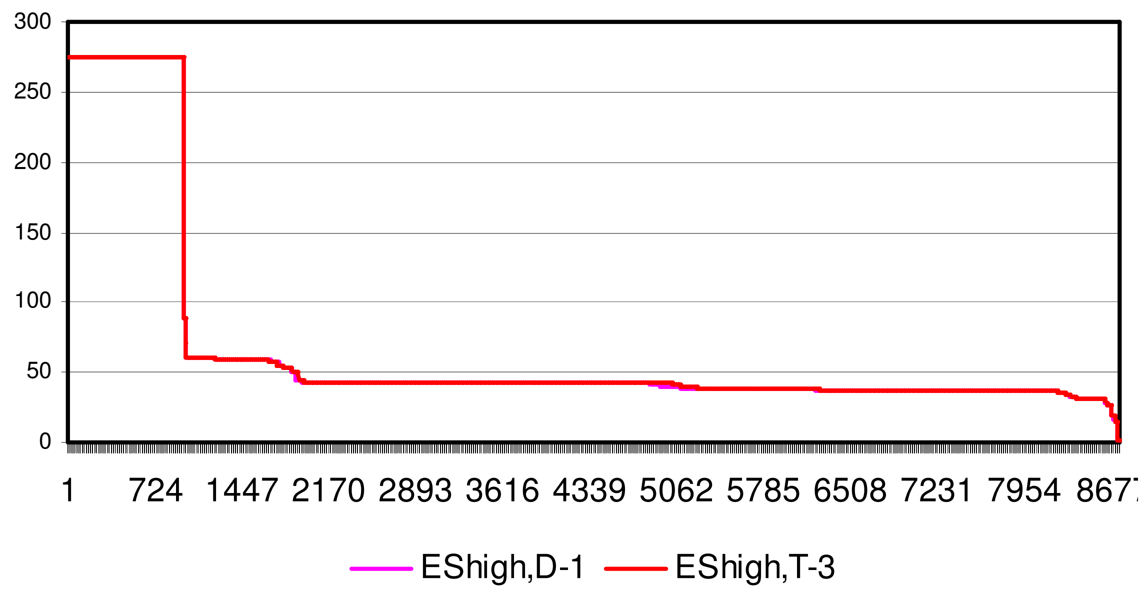

Figure 28. Duration curves of the market clearing prices in Spain for gate closure day-ahead and intra-day (year 2020, best case (high) NTC, medium wind power)

France

For France the differences in clearing price between day-ahead and intra-day gate closure are small but very pronounced for both NTC cases (Figure 29 and Figure 30). The difference of the average clearing price is 0.64€/MWh for *base case* NTC and 0.41 €/MWh for *best case (high) NTC*.

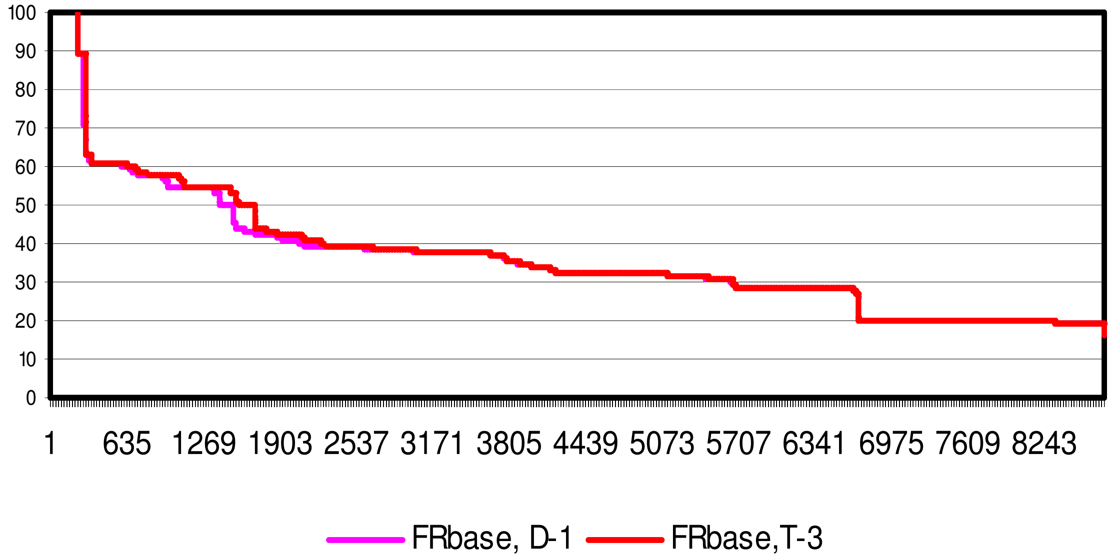

Figure 29. Duration curves of the market clearing prices in France for gate closure day-ahead and intra-day (year 2020, base case NTC, medium wind power)

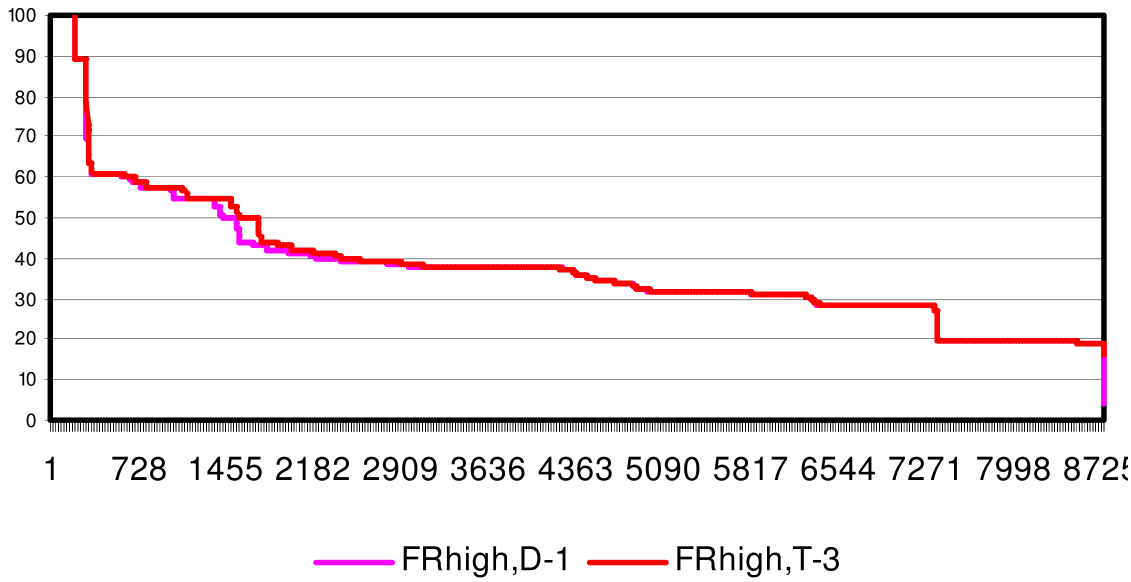

Figure 30. Duration curves of the market clearing prices in France for gate closure day-ahead and intra-day (year 2020, best case (high) NTC, medium wind power)

Great Britain

For Great Britain, the difference between the average market clearing price in scenario *base case NTC, t-3* and average market clearing price in scenario *base case NTC, D-1* is 0.77 €/MWh (Figure 31). The difference of the average clearing prices for the scenarios with *best case (high) NTC* is 0.49 €/MWh (Figure 32).

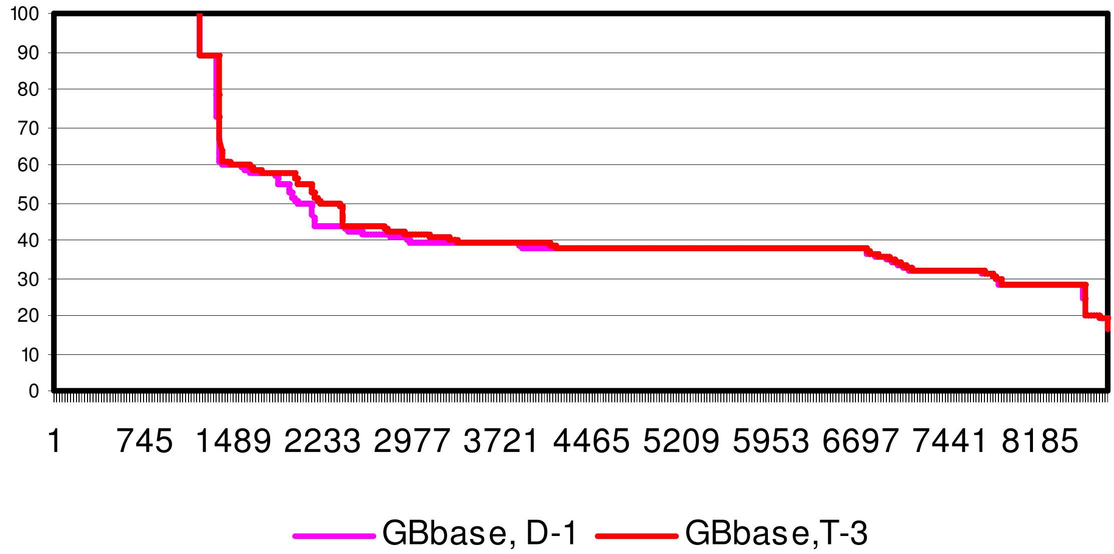

Figure 31. Duration curves of the market clearing prices in Great Britain for gate closure day-ahead and intra-day (year 2020, base case NTC, medium wind power)

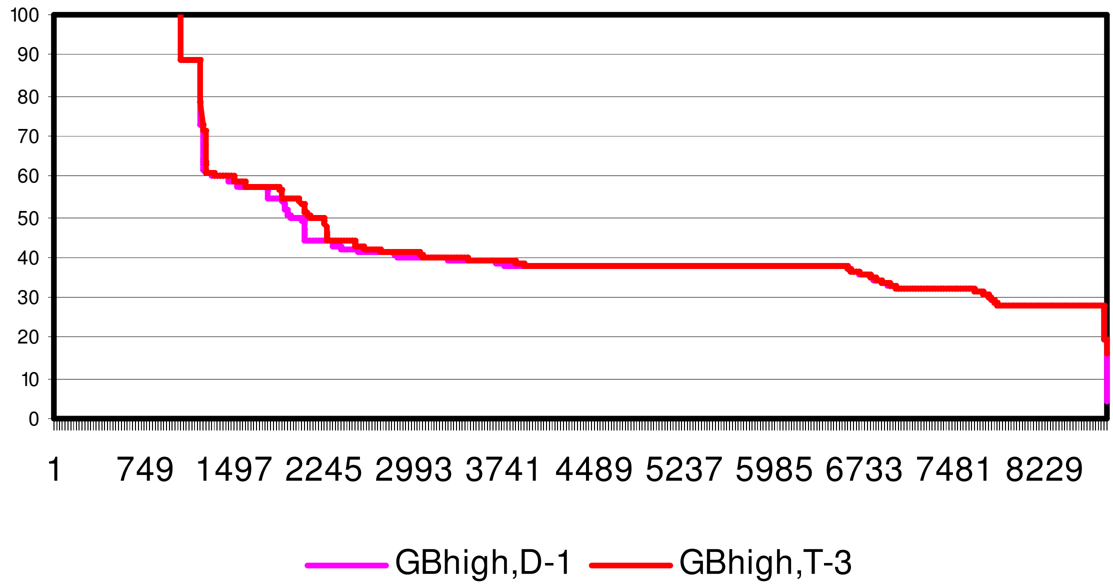

Figure 32. Duration curves of the market clearing prices in Great Britain for gate closure day-ahead and intra-day (year 2020, best case (high) NTC, medium wind power)

Netherlands

For the Netherlands the differences between the average market clearing price in the *base case NTC, t-3* scenario and the average market clearing price in the *base case NTC, D-1* scenario is 0.27 €/MWh (Figure 33). The difference of the average clearing prices for the *best case (high) NTC* scenarios is 0.19 €/MWh (Figure 34).

The differences between the average market clearing price in the *best case (high) NTC, D-1* scenario and the average market clearing price in the *base case NTC, D-1* scenario is 0.71 €/MWh (Figure 35).

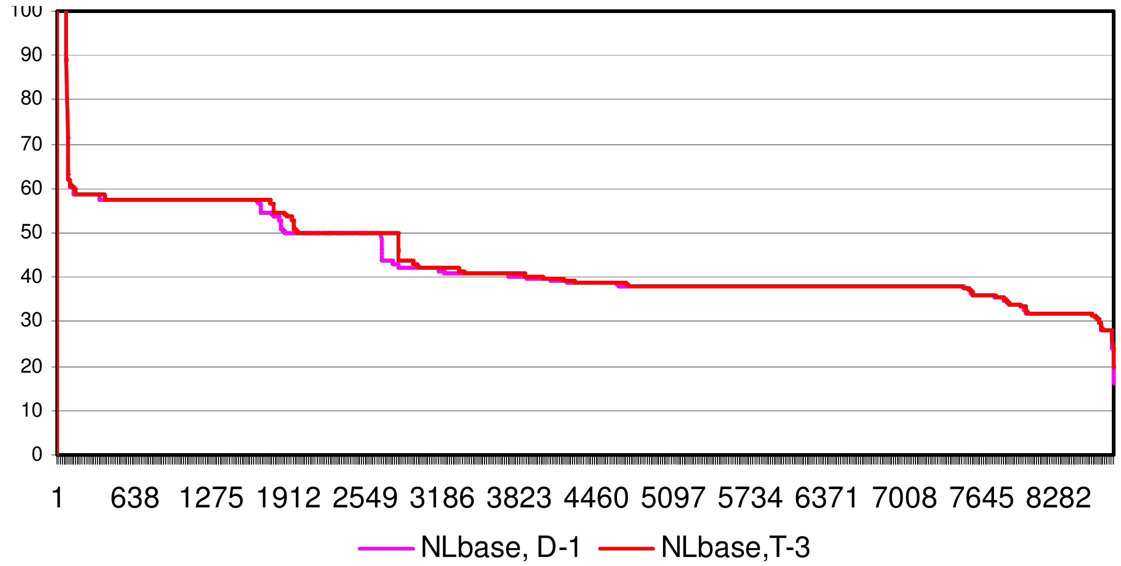

Figure 33. Duration curves of the market clearing prices in the Netherlands for gate closure day-ahead and intra-day (year 2020, base case NTC, medium wind power)

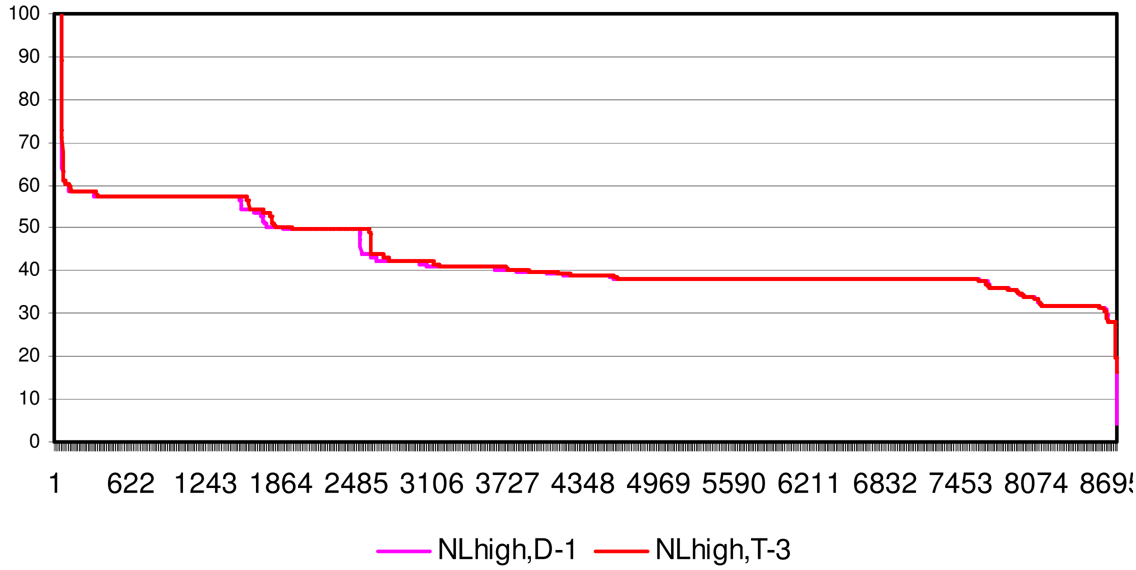

Figure 34. Duration curves of the market clearing prices in the Netherlands for gate closure day-ahead and intra-day (year 2020, best case (high) NTC, medium wind power)

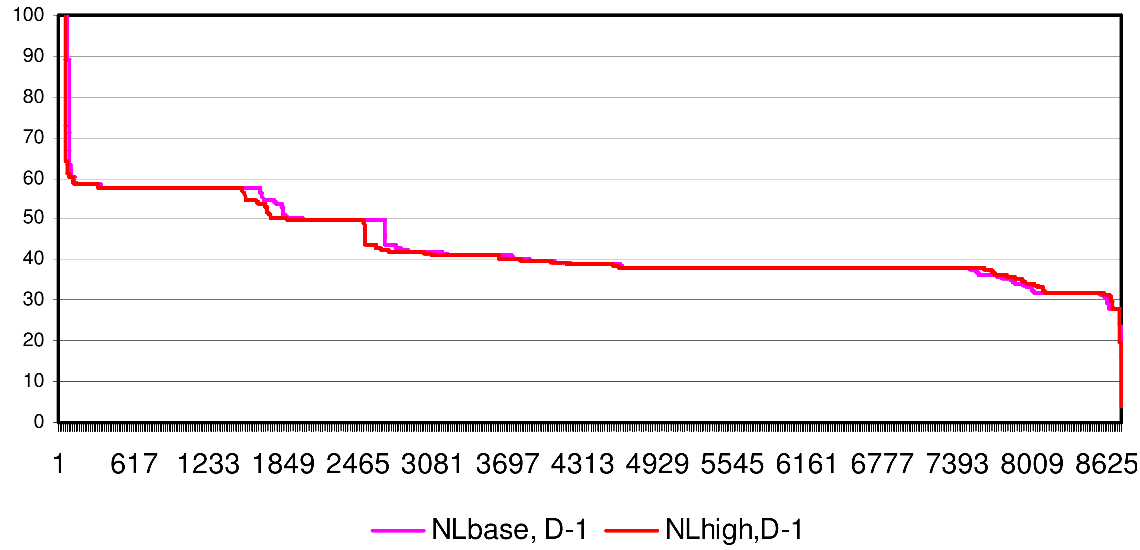

Figure 35. Duration curves of the market clearing prices in the Netherlands for base case NTC and best case (high) NTC (year 2020, gate closure day-ahead, medium wind power)

APPENDIX 4

Wilmar results: average demand for replacement reserves

Table 21 Average demand for replacement reserves in the Wilmar model runs for 2020 dependant on forecast horizon; calculated by averaging over all scenario trees used in 2020; T01 to T32: forecast horizon in hours, reserve demand in MW.

Region	T01	T02	T03	T04	T05	T06	T07	T08	T09	T10	T11	T12	T13	T14	T15	T16	T17	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29	T30	T31	T32
R_AT	465	480	516	532	546	562	581	593	601	609	613	617	625	622	620	623	624	629	633	633	632	625	621	618	619	618	620	628	630	630	635	624
R_B	227	236	255	255	264	269	274	276	280	281	282	282	284	284	284	285	286	287	288	288	288	288	287	287	288	288	287	289	287	285	286	288
R_BU	225	225	226	226	227	228	228	228	229	229	229	229	229	229	229	229	230	230	230	230	230	230	230	230	230	230	230	230	230	231	231	231
R_CH	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318
R_CZ	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495
R_DE	4000	4022	4131	4093	4136	4166	4196	4224	4234	4255	4275	4289	4300	4315	4307	4296	4298	4299	4307	4306	4306	4317	4313	4317	4339	4344	4353	4350	4345	4354	4355	4344
R_DK	185	229	278	287	305	320	330	339	345	351	355	356	357	358	357	358	359	362	361	362	365	369	372	370	368	367	367	374	374	370	367	367
R_ES	1372	1400	1471	1437	1467	1492	1516	1531	1544	1557	1567	1575	1589	1593	1605	1619	1614	1610	1615	1614	1615	1618	1618	1626	1637	1629	1624	1634	1635	1621	1613	1621
R_FR	1310	1387	1507	1527	1568	1609	1655	1691	1715	1745	1764	1785	1810	1822	1829	1842	1848	1841	1851	1860	1860	1859	1859	1869	1874	1858	1867	1882	1874	1877	1908	1889
R_GB	1800	1806	1873	1821	1840	1861	1881	1895	1904	1918	1928	1933	1945	1947	1948	1954	1956	1962	1966	1966	1966	1973	1970	1968	1965	1966	1963	1950	1946	1959	1970	1986
R_GR	349	356	380	387	401	413	425	432	439	446	451	453	454	455	454	456	456	457	459	457	458	462	464	468	466	467	468	468	465	464	474	473
R_HR	80	88.5	97	112	121	128	134	138	141	144	146	147	148	148	149	151	151	152	153	152	153	151	151	151	152	152	152	153	154	153	155	154
R_HU	204	204	205	206	207	208	209	210	210	211	211	212	212	211	210	210	210	211	211	212	211	212	212	212	212	212	212	212	211	211	211	211
R_IR	616	618	636	622	626	632	639	643	646	649	651	653	654	654	655	655	654	655	657	659	658	660	658	659	660	660	661	660	660	660	658	661
R_IT	1663	1664	1672	1667	1670	1673	1677	1681	1684	1690	1693	1697	1698	1698	1700	1701	1699	1699	1700	1702	1701	1703	1703	1703	1705	1702	1703	1705	1710	1707	1710	1708
R_L	31	58	70.1	74.2	80.3	84.9	88.4	90.6	92.6	93.8	94.6	95	95.9	96	96.6	97	97.3	98	98.7	98.7	98.6	98.5	98.2	98.5	98.9	98.9	98.6	97.1	97	96.8	96.5	97.8
R_N	408	476	576	581	616	640	664	682	691	703	709	718	726	729	733	736	739	738	732	733	738	738	734	739	743	745	740	741	741	744	742	736
R_NO	503	503	509	505	506	507	509	511	512	513	513	514	514	514	515	515	515	515	516	516	516	515	515	514	514	516	516	516	515	514	514	514
R_P	252	337	416	504	547	581	612	633	651	669	679	689	699	702	707	710	715	721	727	724	727	730	721	720	718	718	722	730	734	741	747	742
R_PL	725	739	783	780	798	809	824	833	839	843	843	848	849	853	855	852	853	857	860	863	861	862	862	858	861	859	864	873	871	863	860	863
R_RO	354	354	357	356	358	360	362	364	365	366	366	368	368	369	369	369	369	369	369	369	368	368	369	368	368	368	367	368	369	369	368	368
R_SE	569	572	595	579	585	592	599	605	610	614	617	618	622	624	623	623	622	624	623	623	623	625	625	625	627	626	624	629	627	625	629	630
R_SF	464	464	464	464	464	464	464	464	464	464	464	464	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465
R_SK	130	130	132	131	131	132	133	133	134	134	135	135	135	135	135	135	135	135	135	135	135	135	135	135	136	136	136	136	136	136	135	136
R_SV	68	76.1	84.9	88.4	94.2	98.1	102	104	106	108	109	110	110	111	111	112	112	113	114	113	113	114	115	115	114	113	113	114	114	114	115	115

Table 22 Average demand for replacement reserves in the Wilmar model runs for 2030 dependant on forecast horizon; calculated by averaging over all scenario trees used in 2030; T01 to T32: forecast horizon in hours, reserve demand in MW

Region	T01	T02	T03	T04	T05	T06	T07	T08	T09	T10	T11	T12	T13	T14	T15	T16	T17	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29	T30	T31	T32
R_AT	465	497	552	581	608	628	649	659	671	684	685	694	697	697	696	702	705	710	712	710	707	709	709	710	718	718	713	717	719	712	730	730
R_B	227	286	357	377	405	426	441	458	468	474	477	478	483	485	488	486	494	502	502	497	498	504	502	498	502	499	495	499	490	482	483	483
R_BU	225	230	239	247	253	258	263	265	266	268	269	271	273	274	274	275	276	277	276	274	276	279	278	277	279	280	277	278	280	277	278	279
R_CH	318	318	318	318	318	318	318	318	318	318	318	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319	319
R_CZ	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495	495
R_DE	4000	4062	4352	4316	4429	4528	4631	4707	4765	4830	4882	4902	4942	4971	4997	5007	5001	5014	5048	5052	5049	5032	5023	5019	4989	4992	5017	5025	5069	5103	5092	5081
R_DK	185	277	371	392	424	449	470	488	497	508	514	518	524	522	520	522	523	530	533	534	536	541	540	536	532	539	534	534	535	536	546	536
R_ES	1372	1445	1606	1597	1665	1717	1776	1812	1846	1887	1912	1927	1946	1960	1968	1984	1986	1983	1971	1971	1987	1978	1986	1985	1979	2000	2014	2030	2023	2042	2063	2047
R_FR	1310	1510	1729	1811	1883	1960	2052	2132	2211	2271	2319	2349	2391	2406	2426	2462	2469	2461	2434	2444	2428	2445	2451	2455	2467	2487	2492	2522	2516	2504	2530	2515
R_GB	1800	1810	1889	1833	1856	1875	1898	1919	1932	1944	1948	1951	1958	1966	1970	1968	1971	1966	1961	1955	1961	1958	1958	1962	1958	1954	1960	1954	1958	1969	1979	1974
R_GR	349	385	443	482	517	548	571	586	599	611	618	624	628	628	627	630	635	638	639	635	631	629	633	640	649	656	656	669	670	674	678	676
R_HR	80	104	120	172	190	205	215	221	226	230	233	236	239	240	241	246	245	246	249	247	247	250	249	249	251	250	255	258	257	257	262	257
R_HU	204	204	205	207	208	209	210	211	211	211	212	212	213	213	212	212	212	213	213	212	212	212	213	213	213	213	213	213	213	213	213	212
R_IR	616	618	641	626	633	638	645	650	654	658	658	660	663	662	662	663	663	665	664	665	665	665	667	669	667	666	665	669	666	669	668	667
R_IT	1663	1669	1703	1688	1701	1713	1732	1747	1758	1769	1771	1778	1786	1791	1799	1805	1807	1803	1807	1805	1804	1809	1806	1812	1816	1826	1824	1830	1822	1825	1833	1824
R_L	31	59	71	77	83	87	90	93	94	97	98	98	99	100	100	101	101	102	102	102	103	102	102	103	104	104	102	103	103	103	102	103
R_N	408	546	714	748	807	854	888	912	939	961	975	985	988	996	1003	1015	1017	1017	1016	1013	1022	1011	1013	1022	1042	1041	1033	1036	1026	1028	1047	1054
R_NO	503	507	533	516	524	530	536	539	543	544	546	546	548	548	548	550	551	551	551	551	549	549	548	549	548	548	550	548	549	552	553	554
R_P	252	385	496	644	697	736	773	801	820	837	847	859	871	869	874	882	884	891	888	889	897	898	908	916	918	913	916	938	931	931	944	944
R_PL	725	860	1003	1027	1076	1126	1174	1212	1244	1267	1277	1298	1318	1327	1336	1344	1346	1350	1364	1359	1353	1353	1347	1355	1359	1356	1356	1379	1365	1353	1349	1350
R_RO	354	355	362	363	370	376	381	385	388	392	393	395	396	397	397	398	398	398	400	401	399	398	397	398	401	402	403	403	398	397	396	397
R_SE	569	581	636	624	647	669	688	701	710	718	725	729	734	738	741	741	742	742	745	746	746	746	745	745	745	744	742	750	749	747	746	744
R_SF	464	464	472	467	471	474	478	481	483	483	484	486	486	486	488	488	487	487	488	489	489	490	489	490	490	488	488	486	487	487	487	487
R_SK	130	130	132	130	131	132	132	133	133	134	134	134	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
R_SV	68	77	86	89	95	100	104	107	109	111	112	112	114	114	115	116	116	116	117	118	117	118	117	117	119	119	118	118	118	118	119	117

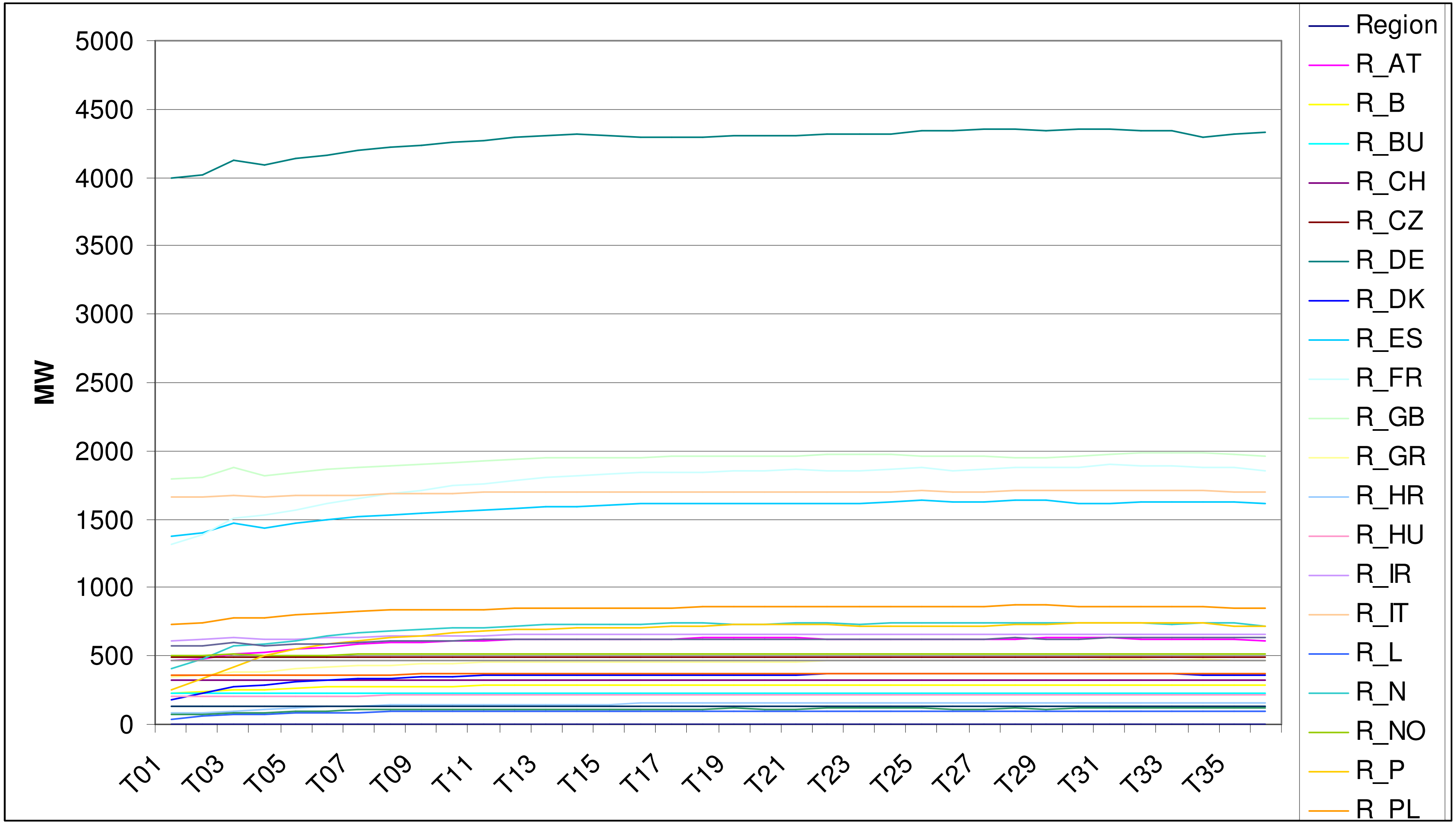

Figure 36. Average demand for replacement reserves in the Wilmar model runs for 2020 dependant on forecast horizon; T01 to T32: forecast horizon in hours

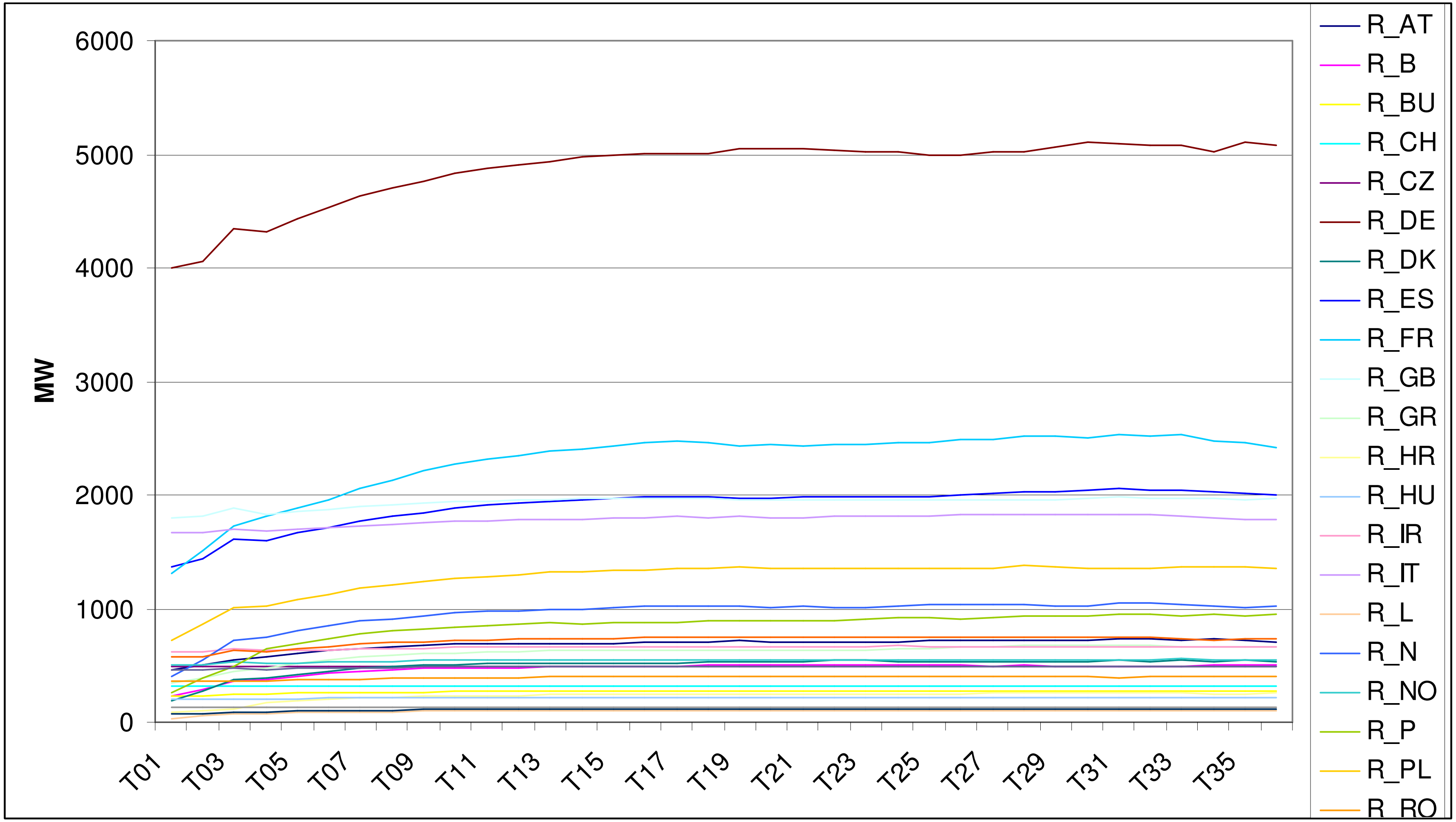

Figure 37. Average demand for replacement reserves in the Wilmar model runs for 2030 dependant on forecast horizon; T01 to T32: forecast horizon in hours